PHD

Overall CO2 Efficiency Assessment for A Low Carbon Energy System

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Contents

Abstract

Decarbonization of the power sector is of great importance for the transition to a sustainable and low-carbon world economy. Estimating carbon efficiency in the power sector is a key step to grasp the impact of demand-side usage changes and evaluate their potential environmental benefits. In order to quantify the environmental benefits of demand-side usage changes, Average Emission Factor (AEF) and Marginal Emission Factor (MEF) have been proposed in the electrical power sector. AEF is defined as the ratio of the total CO_2 emitted in the system to the total electricity generated. It is an effective factor for reporting on CO_2 emissions at system level and on an average basis, but the current AEF model lacks clarity on the factors actually affecting the estimation. MEF is defined as the incremental change in carbon emissions as a result of a change in demand. However, previous MEF assessments did not consider key technical limitations, such as ramp-rate constraint for generators and network constraints, and carbon trading mechanisms. This thesis improves the estimation for both AEF and MEF and key achievements can be summarized as:

1). A novel model of estimating AEF, with its application to GB, US and China's electricity system.

2). Improvement on conventional MEF model by considering ramp-rate constraint in dispatch order.

3). Sensitivity studies on MEF using current fuel prices and future fuel prices.

4). A new model of estimating MEF considering both the utilization level of generators and the carbon costs when determining the dispatch order.

5). The effect of power network on MEF estimation, with a comparison of congested scenarios and non-congested scenario.

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List of Abbreviations

Average Emissions Factor	AEF
Marginal Emissions Factor	MEF
Distributed Generation	DG
European Union	EU
Greenhouse Gases	GHG
University of Bath	UoB
Office of Gas and Electricity Markets	Ofgem
Department of Energy and Climate Change	DECC
Digest of UK energy statistics	DUKES
Great Britain	GB
United Kingdom	UK
Genetic Algorithm	GA
Combined Cycle Gas Turbine	CCGT
Open Cycle Gas Turbine	OCGT
United States of America	US
Emissions Trading System	ETS
Generalized Least Squares	GLS
Fuel Cost	FC
Heat Rate	HR
Emissions Factor	EF
Carbon Cost	CC
Fuel Cost plus Carbon cost	FCC
Generation Cost	GC
Fuel cost of thermal power	F
Combined Heat and Power	CHP
Institute of Electrical and Electronics Engineers	IEEE
Generator to Demand System	GtoD
Ramp Rate Constraint	RRC
Carbon Mechanism	CM

British Broadcasting Corporation	BBC
Department of Environment Food and Rural Affairs	Defra
Her Majesty's Treasury	HM Treasury
International Energy Agency	IEA
Institution of Engineering and Technology	IET
Carbon Price	CP
Fuel-cost-based	FCB
Demand-side Usage Changes	DSUC
Carbon Efficiency of different generation technologies	CE
Energy Mix of power sector	EM
Power Losses	PL
Indirect carbon emissions	Ind

List of Symbols

Carbon Dioxide	CO_2
Water Vapour	H_2O
Methane	CH_4
Nitrous Oxide	N_2O
Ozone	O_3
Kilogram	*kg*
Kilo watt hour	*kWh*
Emissions for h hours	C_h
Power Demand for h hours	D_h
Gig watt hour	*GWh*
Pound	£
Euro	€
Sulfur Dioxide	SO_2
Pence	*p*
Megawatt	MW
Megawatt hour	MWh
Fuel cost of coal	$\mathrm{FC}_{\mathrm{coal}}$
Fuel cost of gas	$\mathrm{FC}_{\mathrm{gas}}$
Heat rate of coal	HR_{coal}
Heat rate of gas	HR_{gas}
Thermal cost for coal	F_{coal}
Thermal cost for gas	F_{gas}
Carbon cost of coal-fired plant	$\mathrm{CC}_{\mathrm{coal}}$
Carbon cost of gas-fired plant	$\mathrm{CC}_{\mathrm{gas}}$
Fuel cost plus carbon cost for coal plant	FCC_{coal}
Fuel cost plus carbon cost for gas plant	FCC_{gas}
Percentage	%

Chapter 1

Introduction

THIS chapter explains the background, context, and motivation for this work. Main contributions of this research and the structure of the thesis are explained also.

1.1 Background

1.1.1 Observed Temperature Changes

The change in our climate is now an important issue in the world. Since the early 20th century, Earth's mean surface temperature has increased by about 0.8 ℃ (1.4 ℉), with about two-thirds of the increase occurring since 1980 [1]. According to recent record, average temperatures have increased by 0.7℃ in the UK since 1659, and central England temperature has risen by a degree Celsius since the 1970s with 2006 being the warmest year on record [2]. Warming of the climate system is completely clear, and scientists are more than 90% certain that it is primarily caused by increasing concentrations of greenhouse gases produced by human activities such as the burning of fossil fuels and deforestation [3]. Human activities of emitting more carbon into atmosphere affect the balance of greenhouse effect, damaging the carbon circle and thus leading to an increase in the temperature.

1.1.2 Greenhouse Effect and Carbon Circle

The Sun powers Earth’s climate, radiating energy at very short wavelengths, predominately in the visible or near-visible part of the spectrum. Roughly one-third of the solar energy that reaches the top of Earth’s atmosphere is reflected directly back to space [1]. The remaining two-thirds are absorbed by the surface and, to a lesser extent, by the atmosphere. To balance the absorbed incoming energy, the Earth must, on average, radiate the same amount of energy back to space. Much of this thermal radiation emitted by the land and ocean is absorbed by the atmosphere, especially by the clouds (greenhouse gases). This is called the greenhouse effect [3, 4] (Figure 1-1). Those gases that absorb and reradiate thermal radiation are called greenhouse gases.

The primary greenhouse gases in the Earth's atmosphere are:

- Water Vapor (H_2O)
- Carbon Dioxide (CO_2)
- Methane (CH_4)

➢ Nitrous Oxide (N_2O)

➢ Ozone (O_3)

Aside from water vapor, which has a residence time of about nine days [5], major greenhouse gases are well-mixed, and take many years to leave the atmosphere. Atmospheric concentrations of greenhouse gases are determined by the balance between sources (emissions of the gas from human activities and natural systems) and sinks (the removal of the gas from the atmosphere by conversion to a different chemical compound) [3]. Higher concentrations of greenhouse gases in the atmosphere can lead to a warming effect on the earth.

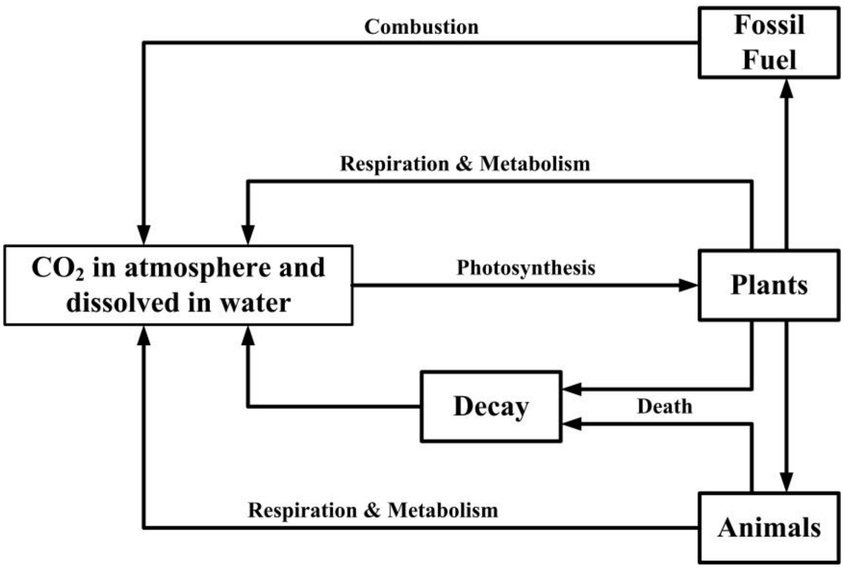

Figure 1-1 Carbon cycle [6]

Since the industrial revolution, human activities have modified the carbon cycle by changing its component's functions and directly adding carbon to the atmosphere [7]. Among these activities, the burning of fossil fuels (oil, coal, or natural gas) is the leading cause of increased anthropogenic greenhouse gases. Fossil Fuels were formed very long ago from plant or animal remains that were buried, compressed, and transformed into oil, coal, or natural gas. The carbon is said to be "fixed" in place and is essentially locked out of the natural carbon cycle. During combustion of fossil fuels in the presence of air (oxygen), carbon dioxide is released into the atmosphere and leads to higher concentration of carbon dioxide in the air. The burning of fossil fuel accounts for about three-quarter of the increase in CO2 from human activity over the past 20 years [7].

1.1.3 Power Sector – the Single Largest Source of Carbon Emissions

Most of the fossil fuels burning take place in the power sector, like coal burning, gas burning and oil burning. According to the Fourth Assessment Report proposed by the Intergovernmental Panel on Climate Change (IPCC), the power sector accounted for 25.9% of global carbon emissions in 2004 (See Figure 1-2), the majority of which is generated from coal. The second largest carbon source is the industry sector, which took up 19.4% of global emissions in 2004. Forestry is the third largest sector, accounting for around 17% of emissions in 2004 [4].

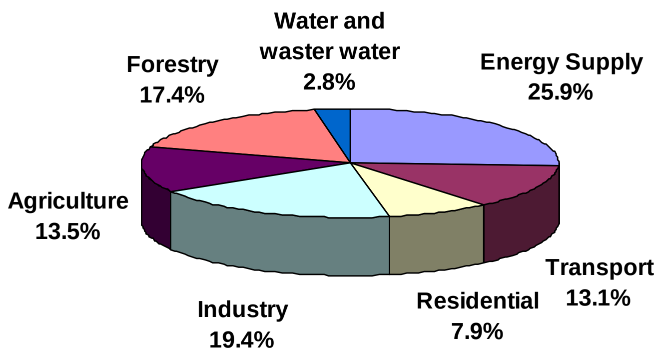

Figure 1-2 Anthropogenic greenhouse gas emissions in 2004 globally [4]

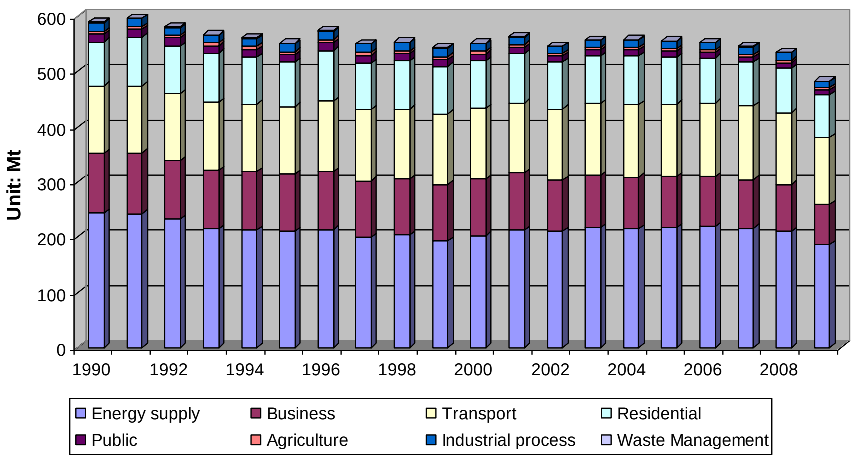

Figure 1-3 GB Carbon Emissions 1990-2009 [8]

In GB, around 39 % of carbon dioxide emissions were made from the power sector in 2009, 25 % from transport, 15 % from business and 16 % from residential fossil fuel use [8, 9]. Decarbonizing the power sector is important, not only for GB, but also for any other country in the world.

1.1.4 Carbon Reduction Target and Demand-side Usage Changes

Given the increasing concern about combating climate change, targets and policies have been set up internationally to reduce anthropogenic carbon emissions. China is said to notably cut CO_2 emissions by 2020, with the target of reducing CO_2 emissions per unit of GDP by 40 to 45 percent from the 2005 levels [10, 11]. President Obama announced in 2009 that the US would achieve a GHG reduction target of around 17% below 2005 levels by 2020 [12-14]. The UK Climate Change Act of 2008 establishes a target of cutting UK's greenhouse gas emissions by at least 80% below base year (1990) levels by 2050 [15]. The Act also introduced a system of carbon budgets which provide legally binding limits on the amount of emissions that may be produced in successive five-year periods, beginning in 2008 [16, 17] (Figure 1-4).

	First carbon budget (2008–12)	Second carbon budget (2013–17)	Third carbon budget (2018–22)	Fourth carbon budget (2023–27)
Carbon budget level (million tonnes carbon dioxide equivalent ($MtCO_2e$))	3,018	2,782	2,544	1,950
Percentage reduction below base year levels	23%	29%	35%	50%

Figure 1-4 UK Carbon Budgets [16]

On the other hand, Demand-side Usage Changes (DSUC) is one of the several important and developing themes to future energy supply. The DSUC is defined as electricity users changing their patterns of use in response to incentives [18-20]. The incentive is normally priced-based tariff or incentive-based program. The priced-based tariff is designed to give customers time-varying rates so that customers are inclined to consume less when electricity prices are high and use more when electricity prices are low. And the incentive-based program is created to pay participants for reducing their usage to meet the balance of electricity supply and demand [19, 21]. Therefore, DSUC has the capability of improving resource-efficiency of electricity production. It can be triggered by electricity balancing and by electricity tariff saving. It also has the potential for being triggered by carbon emissions reducing.

1.2 Research Motivation

Proposed strategies of decarbonizing the power sector consider the potential impacts of both changes to supply-side energy mix and demand-side response [22-24]. On the supply side, generation will be decarbonized through the application of renewable energy and nuclear power, and the use of carbon capture and storage [16]. On the demand side, electrification of heat and transport will be deployed to balance the electricity grid and bring down carbon emissions through demand shift and demand reduction [25-27].

Basically, carbon emissions in the power sector depend upon both demand-side energy use and the carbon intensity of generation units. It is recognized that the potential of demand-side response is increasingly important to ensure future security of electricity supply and to reduce cost and carbon emissions [28]. One important consideration in appropriately managing the demand response is a proper assessment of the impact of demand-side response in terms of carbon emissions, because such an assessment can help demand play a more active role in meeting carbon reduction targets.

Many studies have been taken to investigate the demand-side impacts on carbon emissions. Proposed studies generally attempted to quantify the amount of greenhouse gas emissions caused by energy use and carry out an estimation of how much carbon would be emitted or saved by changing electricity usage, in terms of kg carbon dioxide per kWh of power usage (kgCO2/kWh). Basically, there are two types of methods commonly used to quantify the carbon efficiency in power sector: Average Emission Factor (AEF) and Marginal Emission Factor (MEF) [28-37].

AEF is defined as the ratio of CO_2 emitted to electricity generated, which represents the average $kgCO_2/kWh$ of electricity consumed at the point of final consumption including both carbon emissions from power generators and emissions associated with transmission and distribution losses [38-41]. Based on collected actual data of energy consumption, it is an effective value for monitoring and reporting on carbon foot printing. However, it is inadequate for estimating the marginal effect on the system and for assessing the impacts of demand-side response as a change in demand does not arouse a proportional reaction in all generators. Moreover, the commonly used accounting model for AEF is based on statistical data. It lacks transparency on the factors that affect the AEF. And interdependency between changes in AEF and changes in future energy mix is a big concern in carbon assessment, which has been overlooked.

MEF is widely defined as the incremental change in carbon emissions as a result of a change in demand [28]. Proposed MEFs is a better tool than the AEF for evaluating the marginal savings of carbon reduction due to a change in demand. However, the accuracy of empirical approach based MEF highly depends on the historical data of dispatch and an estimation error is possible if the data available is inadequate. The conventional merit order based MEFs lack some important considerations, for example, technical limits of generator such as ramp-rate constraint, impacts of carbon mechanism on the dispatch merit order, and locational differences of MEFs due to electric network constraints.

To summarize, much improved assessment of carbon emissions in power sector is needed, so as to analysis and project the carbon foot printing in the power sector and to properly acknowledge and reward external benefits of Demand-side response.

1.3 Problem Statement

For the power sector, the AEF is proposed to assess carbon emissions at system level and the MEF is proposed to assess the marginal emissions due to small changes in the system. However, there are some shortcomings that need to be addressed in both the AEF and the MEF estimation.

1.3.1 Deficiencies of Accounting Model for AEF Estimation

AEF represents the average kgCO_2/kWh of electricity consumed at the point of final consumption. It is capable of monitoring and reporting overall carbon emissions at system level and on an average basis. In the GB, AEF is updated by Department of Energy and Climate Change (DECC) to indicate annual carbon efficiency of British electricity system [38-41]. For example, the Average Emissions Factor of 2013 was estimated at 0.5173 kg CO_2 of per kWh electricity consumption. It is based on an accounting model that uses the collected data from energy statistics [42-45], dividing the total CO_2 emitted in the system to total electricity generated.

However, the problem is that such an accounting model is based on statistical data. It does not reflect the main factors that affect carbon emissions in the power sector. Furthermore, due to its data-based characteristic, it is difficult to project AEF for future scenarios with changing energy mixes. Therefore, a proper model of estimating AEF to assess the carbon footprint of power sector is needed. It should make use of the important data in terms of carbon emissions that are accessible in the power sector domain. And the model should be able to get trained properly with historical data so as to achieve better projection for future scenarios.

1.3.2 Overlooking Technical Constraint and Price Changes

The AEF is efficient for the purposes of evaluating emissions footprint in the power sector, however, it is not appropriate to assess marginal carbon benefits from demand-side responses. The MEF is a useful tool of analyzing fuel cost benefit and emission benefit from DSUCDSUC. Many studies of assessing MEF have developed dispatch orders that are based on specific criteria such as fuel cost or utilization level of generators, to examine the marginal impacts of demand changes [35-37]. If it is based on fuel-cost, power plants are assumed to be activated in an order from the most expensive to the least cost. If it is based on utilization, generators are activated by the order of their utilization where the least used generators are curtailed first. However, these assumptions have a flaw, that is, technical properties such as ramp rate is not considered in the analysis. Practically, it is not possible to expect a fast ramp-down of coal power generators. The merit order MEF should be improved by considering the ramp-rate constraint in the dispatch order.

Furthermore, previous estimations of fuel-cost based MEF use the current fuel prices to form the merit order. However, the fuel-cost-based order is very subjective to the prices of fossil fuel like gas and coal which have experienced significant changes in prices over the past ten years. For example, the price of gas has gone up by 125% and price of coal has risen by 48% [46]. Such changes are expected to continue in the future. Therefore, there should be a proper sensitivity analysis, which shows how the results of MEFs might change with different fuel prices.

1.3.3 Neglecting the Impacts of Carbon Mechanism

The fuel-cost-based MEF developed fuel costs based merit orders in which generators are dispatched to meet demand according to minimal fuel costs [29, 35, 36]. It seems to be plausible, as it is generally the case that the cheapest units should be kept online and the relatively more expensive units operate for fewer hours to save the aggregate fuel costs.

However, a fixed fuel-cost-based merit order is insufficient as lower outputs can lead to an increase in fuel costs and the carbon trading mechanism can also have an impact on the generation cost. The utilization-based MEF develop a utilization-based merit order with the highest utilization assumed to be lowest in the merit order [37]. Nevertheless, it does not consider the generation cost and carbon price. The most expensive generator cannot be guaranteed to be curtailed first by this assumption. Therefore, an estimation of MEF without considering both the utilization level of generators and the carbon costs when determining the dispatch merit order, seems to be questionable particularly when mechanisms like carbon taxes or emission trading schemes are introduced to the power sector.

1.3.4 Undifferentiated Network Constraints

In previous studies of estimating MEF, the marginal generators are identified first to examine the marginal emissions due to DSUC, based on specific assumption of dispatch order. Then an average network loss (around 7% -8%) is applied as a top-up rate that is multiplied to the marginal emissions to obtain the results of MEF. However, network impact is much more complicated than a single loss rate. Practically, power losses at different locations of the system are not constant, even there is no congestion in the system. Impacts of network losses on the MEF need to be differentiated with locations.

On the other hand, network constraint in system operation is somehow inevitable. Its impact on Marginal Emissions Factor is possible where network capability is not enough to implement all the generations expected by the pre-assigned merit order. Therefore, it might result in generators with high rank in merit order being prevented from responding and alternative generators being activated to take the transferred power. It is necessary to examine the impacts of network constraints on MEF estimation, although none of the existing works about MEFs takes this into consideration.

1.4 Objectives and Contributions of This Study

The main target of this work is to improve the carbon assessment in the power sector for both AEF and MEF. The AEF estimation is improved by proposing a novel model that can be used to analysis and project the carbon foot printing in the power sector. The MEF is improved by introducing three considerations in the estimation, namely, ramp-rate constraint, impacts of carbon trading mechanism, and network constraints. The main contributions of this work can be summarized as follows:

- A novel model of calculating AEFs is proposed to assess the carbon footprint of electricity consumption at the system level. It is based on the accessible data that have effects on carbon emissions in the power sector, namely, Carbon Efficiency of different generation technologies (CE), Energy Mix of power sector (EM), Power Losses (PL) and Indirect carbon emissions (Ind). It is able to reflect the factors actually affecting the AEF estimation. And it can be used to analyze the current foot print of power sector and to project the carbon emissions for future energy mix. Moreover, in order to achieve better projection for future scenarios, the model is trained by historical AEF data to find out the optimal parameters (CE, PL, and Ind) for the model, using the Genetic Algorithm. British electricity system is used to test the validity of this approach. Three future scenarios (Gone Green, Slow Progression, and Accelerated Growth) are used to project GB's AEF until 2032. AEFs of China and US are also assessed to analyze the current footprint levels of different countries.

- Considering ramp-rare constraints in MEF estimation. The conventional fuel-cost-based merit order method is improved by considering the impacts of ramp-rate constraint of generators. This new method, together with the conventional two merit order method (the conventional fuel-cost-based and the utilization-based), are applied into two typical scenarios of British electricity system (typical winter demand and typical summer demand) to illustrate the potential differences between AEF and MEF in GB. Three fuel prices scenarios are also used to examine how the MEFs change with fuel prices.

- A new merit order with carbon mechanism is developed. It improves the MEFs estimation by considering both the utilization level of generators and the carbon costs when determining the dispatch merit order. The proposed method is applied to two typical demand scenarios to calculate their respective MEFs. The prediction of MEFs for the next ten years is also conducted to assess the impact from demand side intervention over a long-time frame.

- Extending MEFs estimation from energy aspect to power network. The commonly used fuel-cost-based MEF is applied in two test systems to examine how MEFs can change with location and also to analyze the possible MEFs changes due to system constraints. Non-congested scenario and Congested scenario are also implemented to give a better understating of how the MEFs are affected in practical power system.

1.5 Thesis Outline

The rest of this thesis is organized as follows:

Chapter two provides a comprehensive literature review of the existing carbon assessment mechanism in power sector. It begins with the introduction of Average Emissions Factor and its definition. It then goes into the details of AEF in the GB, how often it is reported, its data collection and its limitations. Further, studies on conventional method of assessing MEFs are reviewed and discussed. Their shortcomings and deficiencies are analyzed, so as to pave the way for further improvements.

Chapter three proposes a novel model of estimating AEFs, which is based on the factors that have effects on carbon emissions of power sector, namely, carbon efficiency of different generation technologies, energy mix of power sector, power losses and potential indirect emissions. Demonstrations are given to illustrate how the parameters of the model can be optimally chosen by Genetic Algorithm and how the model can be used to estimate AEFs. Three future energy mixes of the GB (Gone Green, Slow Progression, and Accelerated Growth) are used to project GB's AEF until 2032. And comparisons among GB, US and China are also made to analyze the current footprint levels of different countries.

Chapter four begins with discussions of incorporating technical constraints in MEF assessment. It then discusses the fossil fuel prices changes from the past to future scenarios. A new MEF method of considering ramp-rate constraint in fuel-cost order is proposed. Two typical scenarios of British electricity system (typical winter demand and typical summer demand) are used to illustrate the potential differences among the fuel-cost-based MEF, the utilization-based MEF and the new MEF. Sensitivity analysis of MEFs to fuel prices is made in the end of this chapter.

Chapter five proposes a new MEF method of internalizing emission as a part of generation cost to assess the impact of carbon cost on the generators' profile. Taking into consideration generator's utilization level, it assumes generators are dispatched according to the summation of minimal fuel costs and carbon costs. The most expensive units are curtailed first when demand reduction emerges. The proposed MEF approach and the fuel-cost-based MEF approach are then applied in the British electricity systems in two typical loading scenarios: winter demand and typical summer demand. Effort is also made to project the MEF into the next ten years to assess the impact of demand-side response over a long time horizon.

Chapter six extends MEF estimation from energy aspect to transmission and distribution network. Potential impacts of network constraints on the MEFs are examined by applying the conventional fuel-cost-based MEF in two test systems. Three demand reduction scenarios are also used to see the possible overestimation or underestimation of the cost-based MEF without considering network constraints.

Chapter seven summarizes the key findings from the research and the major contributions of the work.

Chapter eight provides some potential research topics for carbon assessment in power sector.

Chapter 2

Literature Review

THIS chapter begins with discussions of AEF and its key drawbacks. It then reviews the studies on marginal carbon performances of the electric system.

2.1 Average Emissions Factor - AEF

AEF is expressed as the ratio of total CO_2 emissions and total electricity generated [41]. It is an effective value for monitoring and reporting CO_2 emissions at system level based on actual or predicted energy consumption. In previous AEF studies, the estimation is modeled by interpreting two sources of data available in power sector domain as a carbon foot print, namely, the data of monitored electricity consumption and the data of reported carbon emissions.

2.1.1 Studies on Average Emissions Factor

The AEF is quantified by calculating the accumulated emissions during specific time, for example, estimating one AEF for a whole year.

$$AEF_T = \frac{\sum_{h=1}^{T} C_h D_h}{\sum_{h=1}^{T} D_h} \tag{2-1}$$

AEF_T is the average emission factor over T hours (kg CO_2 / kWh), C_h is the emissions for hour h (kg CO_2 / kWh) and D_h is the demand for hour h (kWh). Annual average emissions are frequently quoted to quantify the emissions of all electric applications, regardless of the period of time in which they are operating. The official AEFs of GB's power sector are updated by the DECC annually (T = 8760 hours). These are based on the data shown in Table 2-1 and Table 2-2, collected from Digest of UK Energy Statistics (DUKE). These two tables summarize power generations and carbon emissions in power sector from 1990 to 2011. According to DUKE's report, the data is collected by sending inquiries to companies, covering generating capacity, fuel use, generation and sales of electricity. Inquiries are also sent to electricity distributors, as well as the National Grid, to establish electricity distribution and transmission losses. Companies that generate electricity mainly for their own uses are covered by inquiries commissioned by DECC but carried out by the Office for National Statistics (ONS) [42-46].

Table 2-1 Electricity generation data from 1990 to 2011 [45]

Year	Electricity Generation (GWh)	Electricity Consumption (GWh)	Total Grid Losses
1990	290,666	267,180	8.08%
1991	293,743	269,450	8.27%
1992	291,692	269,669	7.55%
1993	294,935	273,788	7.17%
1994	299,889	271,190	9.57%
1995	310,333	282,186	9.07%
1996	324,724	297,447	8.40%
1997	324,412	299,140	7.79%
1998	335,035	306,892	8.40%
1999	340,218	312,150	8.25%
2000	349,263	319,995	8.38%
2001	358,185	327,524	8.56%
2002	360,496	330,719	8.26%
2003	370,639	339,246	8.47%
2004	367,883	335,840	8.71%
2005	370,977	344,081	7.25%
2006	368,314	341,759	7.21%
2007	365,252	338,443	7.34%
2008	356,887	330,299	7.45%
2009	343,418	316,391	7.87%
2010	348,812	323,279	7.32%
2011	330,128	304,114	7.88%

Table 2-2 Emissions data from 1990 to 2011 [45]

Year	UK Electricity Generation Emissions (ktonne)			
	CO_2	CH_4	N_2O	Total
1990	204,614	2.671	5.409	204,622
1991	201,213	2.499	5.342	201,221
1992	189,327	2.426	5.024	189,334
1993	172,927	2.496	4.265	172,934
1994	168,551	2.658	4.061	168,558
1995	165,700	2.781	3.902	165,707
1996	164,875	2.812	3.612	164,881
1997	152,439	2.754	3.103	152,445
1998	157,171	2.978	3.199	157,177
1999	149,036	3.037	2.772	149,042
2000	160,927	3.254	3.108	160,933
2001	171,470	3.504	3.422	171,477
2002	166,751	3.49	3.223	166,758
2003	177,044	3.686	3.536	177,051
2004	175,963	3.654	3.414	175,970
2005	175,086	3.904	3.55	175,093
2006	184,517	4.003	3.893	184,525
2007	181,256	4.15	3.614	181,264
2008	176,418	4.444	3.38	176,426
2009	155,261	4.45	2.913	155,268
2010	160,385	4.647	3.028	160,393
2011	148,153	4.611	3.039	148,161

Based on the above results, the UK's AEFs are assessed and published by the DECC. To hand out the AEFs with year to year comparability, the published AEFs in UK are presented as 'Grid Rolling Average', which is the average of the grid average emissions factors over the last 5 years.

Table 2-3 Grid Rolling Average of AEF from 1990 to 2011 [41]

Year	AEF (kgCO_2e / kWh)
1990	0.77229
1991	0.75309
1992	0.70801
1993	0.63662
1994	0.62639
1995	0.5917
1996	0.55828
1997	0.51302
1998	0.51555
1999	0.48041
2000	0.50616
2001	0.52701
2002	0.50742
2003	0.52533
2004	0.52733
2005	0.51226
2006	0.54371
2007	0.53911
2008	0.53759
2009	0.49389
2010	0.49933
2011	0.49056

2.1.2 Key Drawbacks of AEF

First of all, AEF is insufficient for representing demand response, as a change in demand does not reflect a proportional reflection in all generators [28]. For example, corresponding to any demand change happening in the system for a period of time, only those generators which are capable of adjusting output with the demand change would be activated. Those generators are known as marginal plants and the AEF as a system-level estimation is not justified in assessing the behaviours of the marginal plants. Incorrect use of AEF for marginal assessment can lead to a misleading estimation of carbon emissions.

Secondly, the existing accounting model of estimating AEF lacks clarity on the factors actually affecting the estimation, and its robustness against changing energy mix is questionable. Basically, many countries around the world generate electricity with big proportions of fossil fuel (coal, gas and oil) in the energy mix, leading to an increase of greenhouse gas emissions in the atmosphere. In order to continue developing while preserving the environment, energy mixes in most countries are likely to change dramatically as carbon emissions have become a big concern globally.

In the GB, three future energy mixes till year 2032 have been estimated to meet the emission targets set out by the government, namely Slow Progression scenario, Gone Green scenario, and Accelerated Growth scenario. The Slow Progression scenario has a lower emphasis on renewable generation over the period to 2032. The Gone Green scenario assumes a generation mix that will be able to meet the CO_2 and renewable targets. The Accelerated Growth scenario has a much steeper increase in the level of renewables generation capacity than Gone Green and Slow Progression [47].

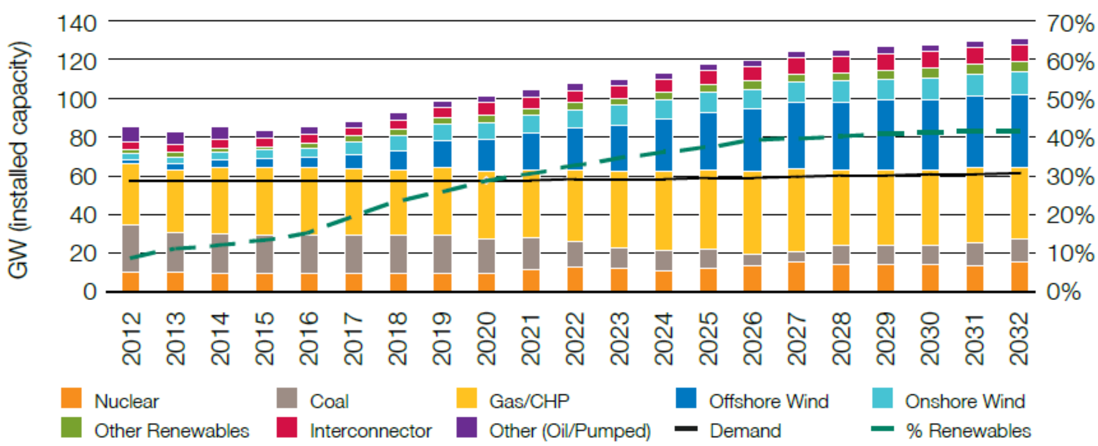

Figure 2-1 Gone Green Future Energy Mix [47]

Take the Gone Green scenario as an example (Figure 2-1), capacity of coal-fired power plant is expected to decrease dramatically over the period to 2032, with the existing 25 GW decreasing to 18 GW by 2020 and to 12 GW by 2032. Wind-power capacity is expected to reach 25 GW of capacity by 2020 and 49 GW by 2032.

These changes will by all means reshuffle the energy mix, going from a fossil-fuel dominated mix to a much greener mix. However, the existing accounting model, based on the statistical data, is not justified in assessing the interdependency between changes in AEF and changes in energy mix. Therefore, a reasonable model of estimating AEF, which accounts for the factors that affect carbon emissions and is suitable for future projection, is undoubtedly necessary.

2.2 Marginal Emissions Factor - MEF

Given AEF's insufficiencies in demand-response assessment, MEF is proposed. This is considered to be a better instrument to evaluate the marginal change of carbon emission, due to a change in demand [28-37]. Previous studies on quantification of such marginal change can be classified into three categories: single marginal plant approach, merit order approach and empirical approach (Figure 2-2).

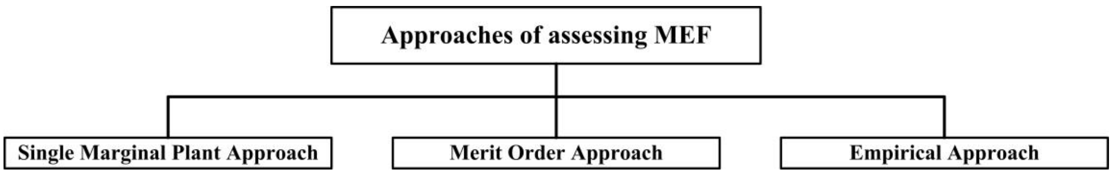

Figure 2-2 Approaches of assessing MEF

2.2.1 Single Marginal Plant Assumed MEF

While the AEF should be used for reporting emissions of electricity use and footprint, the MEF is useful for analysing benefits of sustained demand changes in consumption. The MEF is intended to reflect the actual change in emissions that would result from a small but sustained change in electricity consumption [48]. It is mainly determined by the marginal plants whose output is increased or decreased, when there is a sustained but marginal change in the system demand. In Valuation of Energy Use and

Greenhouse Gas Emissions for Appraisal, the DECC estimates the marginal plant to be a single CCGT plant. It is based on the assumption that Combined Cycle Gas Turbine (CCGT) plant is and will reflect as a significant part of the marginal impact. It is a flexible technology and quick to build. The MEF is then estimated to be the effect of this CCGT plant plus a fixed rate of system power loss (Table 2-4).

Table 2-4 MEFs by UK government [48]

Year	Generation-side kgCO_2e / kWh	Assumed grid losses	Consumption-side kgCO_2e / kWh
2010	0.3464	7.50%	0.3723
2011	0.3400	7.50%	0.3655
2012	0.3333	7.50%	0.3583
2013	0.3261	7.50%	0.3505
2014	0.3184	7.50%	0.3422
2015	0.3101	7.50%	0.3334
2016	0.3014	7.50%	0.3240
2017	0.2920	7.50%	0.3139
2018	0.2820	7.50%	0.3031
2019	0.2713	7.50%	0.2917
2020	0.2599	7.50%	0.2794

CCGT plant is an important marginal plant and has a significant impact on the MEF. However, going forward over time, other plants including the coal-fired and low carbon technologies are also accountable for marginal impacts. There are reasons to think that MEF might not be determined by a CCGT unit only. For example, policies are in place to give incentive to low-carbon generators being more active, and many efforts are being made to make the coal-fired more flexible. Therefore, assessment of MEF should consider the potential choices of marginal generation technologies and estimation should be made based on a series of demand reduction scenarios.

2.2.2 Merit Order Based MEF

In power generation, power plants can be classified into two types, namely, base-load power plant and marginal power plant. A base-load power plant is a power station that provides a continuous electricity supply to customers, with the character of slow demand respond. It is not capable of meeting flexible demand or responding to the DSUC. A marginal power plant is a plant that can adjust its output of electricity generated to balance the changing demand throughout the day and it is capable of taking the DSUC.

Studies of estimating MEF using merit order approach attempt to assess the possible behaviours of marginal plants in the system to reflect the marginal impacts of the DSUC on carbon emissions. It assumes the marginal plants to be triggered according to some specific criteria such as fuel cost and utilisation level of generators. For cost-based criteria, marginal power plants are activated according to fuel cost, from high to low. For utilisation-based criteria, marginal generators are activated according to their utilisation order, where the least used generators are activated first in response to demand change.

For a cost-based order, Kris Voorspools [35-36] activated generators in the electricity system considering their fuel costs, whereas generators with highest running cost are stopped first, with demand reduction. Based on the data of Belgian electricity system in 1997, generators in Belgium were modulated in the order of Table 2-5 [35]. So, for any demand change, the most expensive generator (Open Cycle Gas Turbine, OCGT) would be the first to response to this change. In Kris's study, MEF was estimated to be around 1000 g CO_2 per additional kWh, after applying some additional demand patterns to the existing overall electricity demand.

Table 2-5 Fuel cost for generators [35]

Rank	Generator	£/ MWh
1	OCGT	16.1133
2	Pump Unit	10.5954
3	Coal	10.3174
4	CCGT	10.0192
5	Nuclear	5.7213
6	Hydro	0

Chris Marnay [29] used similar cost-based order to calculate MEFs for the Californian electricity network. He used a model called Elfin, Electric Utility Financial & Production Cost Model, to consider generators' response to demand changes. The model is based on electricity production cost. He concluded that MEFs could range from 25 to over 200 per cent higher than the corresponding AEFs. Further, using AEFs to estimate the CO_2 savings from reducing electricity usage would significantly underestimate actual savings [29].

For an utilisation-based merit order, R. Bettle used the historical data from the power systems of England and Wales in 2000, to develop a utilization-based merit order, with the highest utilization as being lowest in the merit order [37]. He used half hourly operational data of power plants to decide the loading level of generators on a half-hourly basis. Generators were then ranked according to their loading percentage and a utilization-based merit order was then formed. This method is based on the assumption that generators generating close to their capacity were up most of the time and therefore must be higher up in the real merit order to be able to achieve this [37]. His analyses showed that, when electricity demand peaked in winter, the general order is nuclear, CCGT, oil and coal. Examining the differences between the AEF and the MEF for the case of England and Wales, he concluded that MEF was up to 50% higher than the system average emission factor and the use of the system average factor was likely to seriously underestimate short-term carbon savings.

Comprehending this, studies of assessing MEF with merit order approach assume a possible order of dispatch to estimate the marginal changes in CO_2 emissions as a result of demand change. However, some deficiencies of the existing studies need to be improved:

- Most of the studies are generally applied to current electricity system only, which is of limited use as the future marginal plants may be vastly different from those of today. Projection of MEF into future is imperative as carbon plan is a long-term scheme.

- The fuel-cost-based approach seems to be plausible, as generally the cheapest units should be kept online and the relatively expensive units operate for fewer hours to save aggregate fuel costs. But a fixed fuel-cost-based merit order is not justified, as lower outputs can lead to an increase in fuel costs and the carbon mechanism can also have a major impact on the generation cost.

- The assumption of utilization-based order is reasonable because most conventional units are designed to be the most efficient when operating at rated output and their efficiencies reduce when operating at lower outputs. However, this assumption cannot guarantee that the most expensive generator would be the first to be curtailed. Also, it does not consider the impact of carbon mechanism, which may change the order of dispatch.

- Proposed merit order approaches are either based on economic efficiency (fuel cost) or utilization level of generators. However, the MEF assessment can be further improved by taking into consideration both the technical constraints and network impacts. Generators might not be able to respond in arranged order due to technical or network constraints, and a local generator placed lower in the rank can be the first to respond to the demand change.

2.2.3 Empirical Approach MEF

Hawkes [34] proposed a methodology that uses linear regression to estimate the average response of each generation technology class, to changes in system load, which is called the Empirical Approach. He disaggregated historical data of generator dispatch and carbon emissions to examine the influence of marginal effects. The input data sources for this analysis are:

- Dispatch data for every major power producer in Great Britain from the beginning of 2002 until the end of 2009 (available from Elexon 2010) [49];

- The Digest of UK Energy Statistics (DECC 2009) [42];

- The 2009 GB Seven Year Statement [50].

Based on these data, Hawkes calculated *n* observations of system CO_2 emissions over a period of time. Correspondingly, a vector of *n* observations of total system load for each settlement period was calculated. The first difference of these vectors was calculated, to arrive at vectors of *n*-1 observations of the change in system CO_2 emissions and corresponding change in system load. A linear regression of these two vectors was then performed and the slope of this line was considered to be an estimate of the MEF over that time period [28]. Figure 2-3 is an illustration of how MEF was calculated in Hadland's study.

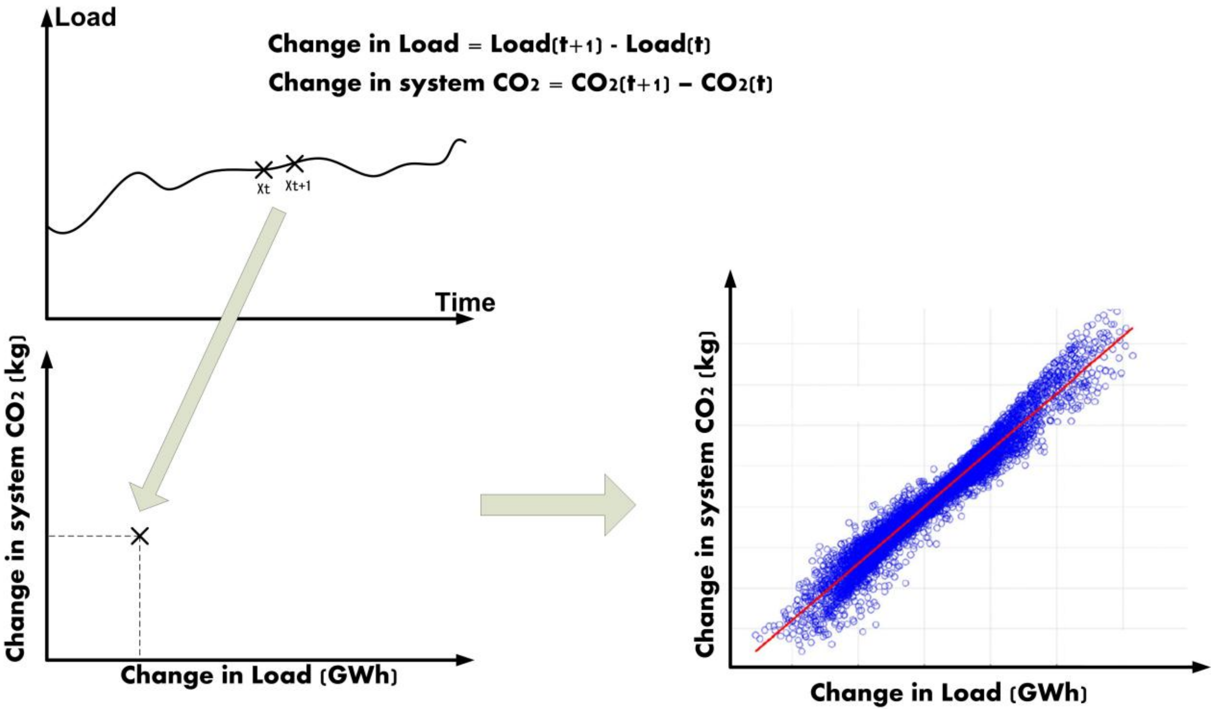

Figure 2-3 An Empirical Approach of Assessing MEF

The empirical approach has the advantage of incorporating technical properties of the power system, for example, grid constraints and power losses. Nevertheless, the accuracy of this methodology depends primarily on the historical dispatch data, and an estimation error is possible due to inadequate data. Additionally, the future energy mix is expected to have bigger portion of renewable technology and less fossil-fuel generation. However, changes in energy mix is out of the scope of the existing MEF estimation, and impact of low carbon incentives like carbon price is difficult to be incorporated in the empirical model.

2.3 Chapter Summary

This chapter reviews existing researches on both the AEF and the MEF, so as to pave the way for further improvement. Details are given to explain the existing methods and detail out their limitations. Shortcomings and drawbacks of the existing methods can be summarized as:

- The existing accounting model of estimating AEF lacks clarity over the factors that affect carbon emissions in power sector. A reasonable model that considers the changing energy mix is required.

- Single marginal plant is a plausible but inadequate assumption for estimating MEF. The estimation can be improved by considering the potential choices of marginal generation technologies, with a series of demand reduction scenarios.

- Many studies of assessing MEF tried to develop a merit order of dispatch according to some specific criteria, so as to examine the marginal impacts of changes in demand. But the Merit Order Approach can be improved by considering three important factors, namely, technical limits of generator such as technical constraint, impacts of carbon mechanism on the dispatch merit order, and locational differences of MEFs due to electric network constraints.

- Accuracy of Empirical Approach depends on the historical dispatch data and an estimation error is possible if the data available is inadequate. It is difficult to consider changing energy mix and carbon mechanism in this model.

Chapter 3

Estimating Average Emissions Factor

THIS chapter proposes a novel model of estimating AEF to assess the carbon footprint of power sector. Demonstrations are also given to test the effectiveness of the model.

3.1 Introduction

In this chapter, a novel method of calculating Average Emissions Factor (AEF) is proposed. The proposed model is based on four important factors that have effects on carbon emissions in power sector:

- Carbon efficiency of different generation technologies;
- Energy mix of power sector;
- Power losses;
- Potential indirect emissions such as fuel exploration and fuel transport.

To test the validity of this approach, GB electricity system is used to estimate the Average Emissions Factors in the Great Britain. The obtained results are compared with the DECC's AEFs which are based on an accounting model. Demonstrations are given to illustrate how the parameters of the model are chosen by Genetic Algorithm and how it can be used to estimate AEFs. Comparisons between the actual AEFs and the results by this model provide evidence to the effectiveness of this tool. In order to project AEFs over a long-time framework, three future energy mixes of the GB (Gone Green, Slow Progression, and Accelerated Growth) are used to project GB's AEF until 2032. And comparisons among GB, US and China are also made to analyze the current footprint levels of different countries.

3.2 Factors Affecting Carbon Emissions

The AEF is to estimate the overall carbon efficiency of an electricity system. Therefore, it needs to adequately reflect the factors that have impacts on the carbon emissions. In order to set up the model of estimating AEF, four factors are considered and analyzed in this chapter.

3.2.1 Carbon Efficiency of Different Generation Technologies

Carbon emissions in power sector are produced mainly by generators. An efficient AEF assessing model should be able to consider carbon emissions of different technologies.

The carbon efficiency of a generator depends on two factors. One is the fuel factor, known as the gases produced in the combustion of getting energy, in terms of kg carbon dioxide per kWh of energy released. The other one is generation efficiency from energy to electricity, which differs with different generation technologies. Therefore, the carbon efficiency of a generator can be expressed as following:

$$\underset{(kg\ equivalent\ CO2\ per\ kWh\ electricity)}{Carbon\ Efficiency} = \frac{Fuel\ Factor\ (kg\ equivalent\ CO2\ per\ kWh\ energy)}{Electrical\ Efficiency} \tag{3-1}$$

In electricity industry, main sources of carbon emissions are coal-fired power plant, Open Cycle and Gas Turbine power plant (OCGT), Combined-Cycle Gas Turbine (CCGT), Oil-fired power plant and Pumped-storage hydroelectricity.

3.2.1.1 Combined Cycle Gas Turbine - CCGT

Combined Cycle Gas Turbine (CCGT) is a form of highly efficient energy generation technology that combines a gas-fired turbine with a steam turbine [51]. The design (see Figure 3-1) uses a gas turbine to create electricity and then captures the resulting waste heat to create steam, which in turn drives a steam turbine significantly increasing the system's power output without any increase in fuel. CCGT is the dominant gas-based technology for intermediate and base-load power generation currently. Its electrical efficiency is expected to increase from the current 52–60% to some 64% by 2020.

The fuel used in the CCGT for electricity generating is natural gas. It is a gaseous fossil fuel that is versatile, abundant and relatively clean compared to coal and oil, formed from the remains of marine microorganisms. Natural gas is composed primarily of methane (about 95%), but may also contain ethane, propane and heavier hydrocarbons. Small quantities of nitrogen, oxygen, carbon dioxide, sulfur compounds, and water may also be found in natural gas.

Chemically, the combustion of natural gas mainly consists of a reaction between methane and oxygen. When this reaction takes place, the result is carbon dioxide (CO_2), water (H_2O), and a great deal of energy. Chemists would write the following to represent the combustion of methane [52]:

$$CH_4[g]+2O_2[g] \;\rightarrow\; CO_2[g]+2H_2O[l]+891kj \tag{3-2}$$

That is, one molecule of methane (the [*g*] referred to above means it is gaseous form) combined with two oxygen atoms, react to form a carbon dioxide molecule, two water molecules (the [*l*] above means that the water molecules are in liquid form, although it is usually evaporated during the reaction to give off steam) and 891 kilojoules (*kJ*) of energy [52]. If the CCGT electrical efficiency is considered by around 52–60%, the carbon efficiency of CCGT plants is around 0.28 to 0.33 kg CO_2 per kWh electricity.

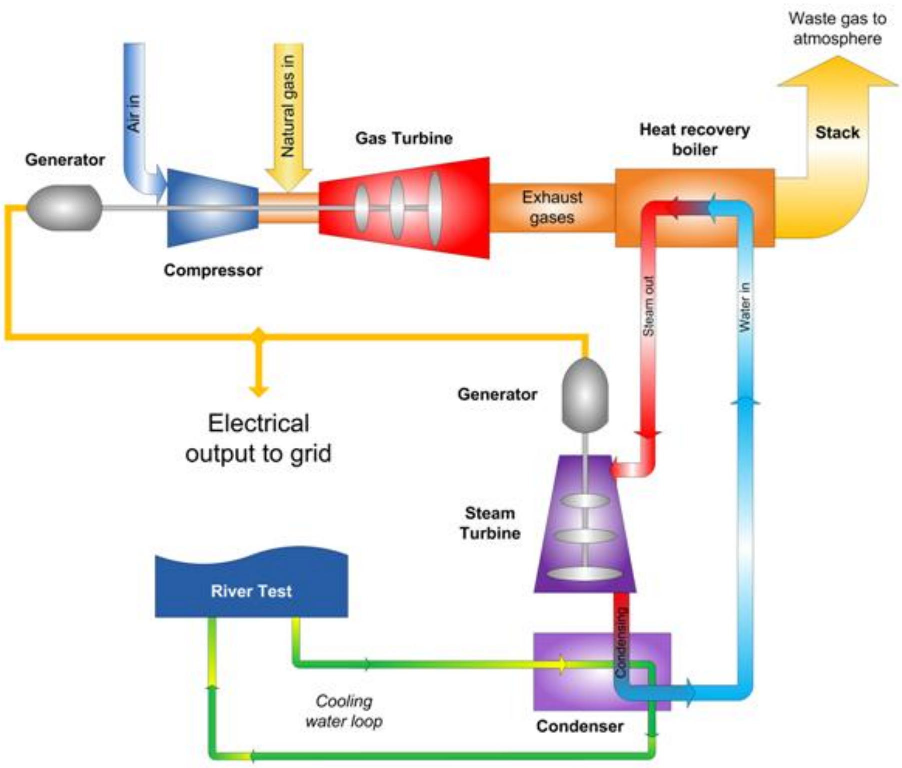

Figure 3-1 Working principle of a combined cycle power plant [51]

3.2.1.2 Open Cycle Gas Turbine - OCGT

Open Cycle Gas Turbine (OCGT) for electricity generation was introduced decades ago for peak-load service [53]. It is able to provide flexible and frequent responses for systems requirements for supporting peak demand and backing up renewable energy sources in times of low wind speed. OCGT plants have the same basic components as the OCGT plants but the heat associated to the gas-turbine exhaust is not used. The fuel used in the OCGT for electricity generating is natural gas as well. But its electrical efficiency is far lower, 35% to 42% at full load. So the carbon efficiency of OCGT plants is around 0.41 to 0.49 kg CO_2 per kWh electricity.

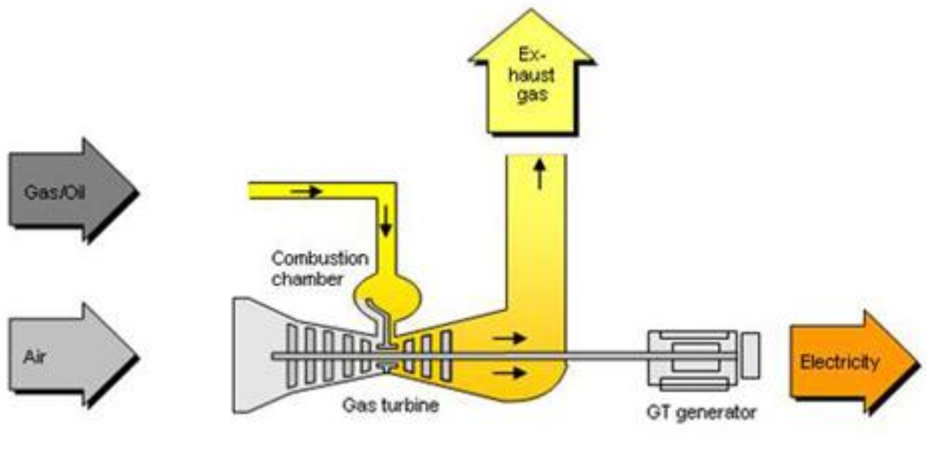

Figure 3-2 Working principle of an open cycle power plant [53]

3.2.1.3 Coal-fired Power Plant

A coal-fired power station is a type of power station that burns coal to produce electricity [54]. It has rotating machinery to convert the heat energy of combustion into mechanical energy, which then operates an electrical generator.

Because of the various degrees of transformation that occurred during the forming of coal deposits in different locations, the composition of coal varies from one deposit to another. No two coals are the same in every respect. In general, coal consists of carbon (90%), hydrogen (3%), oxygen (2%), nitrogen (1%), sulphur (1%) and mineral matter (including compounds of silicon, aluminum, iron, calcium, magnesium and others). Therefore, the burning of main constituent in coal-fired power plant is the combustion of carbon, resulting in emitting carbon dioxide.

Conventional coal-fired plant produce electricity at 30% to 38% delivered thermal efficiency, which means that additional two thirds of carbon emissions can be produced due to the low conversion efficiency from energy to electricity, thus tripling emission factors for coal-fired technology approximately. So the carbon efficiency of the coal-fired plants is around 0.85 to 1.05 kg CO2 per kWh electricity.

3.2.1.4 Oil-fired Power Plant

An oil-fired power station is a type of power station that burns oil to produce electricity. The Oil supplies only 1.2% or less of the GB's electricity. There are very few oil-fired power stations in the GB. However, the conventional Oil-fired plants operate at 25% to 29% efficiency, and they are not environmental-friendly generations. So the carbon efficiency of the Oil-fired plants is around 0.92 to 1.06 kg CO2 per kWh electricity.

3.2.1.5 Pumped-Storage Unit

Pumped-storage hydroelectricity is a type of hydroelectric power generation, storing energy in the form of water from a lower elevation reservoir to a higher elevation for load balancing [56-67]. Its efficiency can be assumed to be 75%, and then its carbon efficiency is estimated to be the division of annual average over 75%.

3.2.2 Energy Mix of Power Sector

Apart from the carbon efficiency of generators, energy mix is another important factor that is linked to carbon emissions in power sector. The energy mix is defined as the proportions of energy used to meet the needs of electricity.

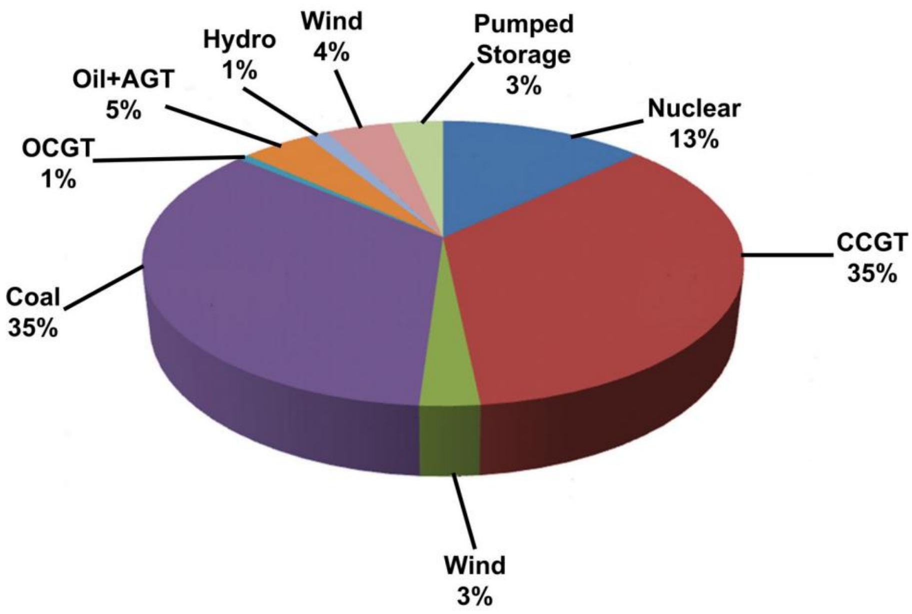

Figure 3-3 GB's Generation mix in 2011 [47]

In the GB, the Electricity generation roughly consists of three major groups of power plant: nuclear power, Combined Cycle Gas Turbine (CCGT) plants, and coal-fired units. The nuclear power plants provide base load power generation, which supplied around 15% of all electricity generation in 2011, with a capacity of 10.843 GW. The second generation group is CCGT units, providing around 38% in the winter and 51% in the summer of the electri20city, with a capacity of 29.022 GW. The third generation group is coal-fired power plants, which supplies 40% in the winter and 28% in the summer of electricity demand, with a capacity of 28.789 GW. Apart from these main groups, pumped storage power plants are widely used in the GB to supply necessary generation gap during the peak demand, 0.66% in the winter and 1.13% in the summer, with a capacity of 2.744 GW. Open Cycle Gas Turbine (OCGT) plants are normally only used in maximum winter demand when the system loading level is at its highest throughout the year, with a capacity of 0.5789 GW. The generation mix of British electricity system in 2011 is shown in Figure 3-3. The energy mix from 2011 backward to 2000, including all generation technologies, can be found in [50].

Since the 19th century, the energy sources used to meet electricity demand have been mostly fossil-fuel power plants, for example, the coal-fired and the gas-fired. But, for many countries, their energy mixes are set to change dramatically over the next 20 years [47]. In the GB, three future energy scenarios (Slow Progression, Gone Green and Accelerated Growth) have been considered to provide a range of potential developments and outcomes. Each scenario has its own generation mix assumption, as outlined in the following:

- Slow Progression. Compared with the other two scenarios, it plans less renewable generation, slower decline in coal-fired unit and more increase in gas capacity over the period. The key changes to 2032 are shown below [47]:

    - Gas generation increases over the period to 2020 by 7 GW and to a total of 49 GW by 2032 showing a total increase over the period of 16 GW;

    - Growth in wind generation is considerably slower in this scenario in comparison to Gone Green and Accelerated Growth and reaches 13 GW by 2020 and 28 GW by 2032 (19 GW being offshore wind), showing a total increase over the period of approximately 22 GW (the vast majority of this being offshore wind);

    - Other renewables excluding wind remain fairly static over the full period to 2032 showing only approximately a 300 MW increase;

    - The coal-fired shows a slower decline than in the Gone Green scenario showing a 7 GW decrease by 2020 leaving 18 GW of coal capacity. Between 2020 and 2032 coal declines further, to 4 GW by the end of the period;

    - Nuclear power remains fairly static over the period rising from 10 GW in 2012 to 13 GW by 2030 before falling back to 11 GW by 2032;

- The existing level of renewables at 2012 in this scenario is 8.5%, which will rise to 17% in 2020 and finally increasing to 30% in 2032.

- Gone Green. Based on the target of meeting renewable energy over the period, it assumes a generation mix that will include more renewable energy than the Slow Progression. The key changes to 2032 are shown below [47]

  - Wind generation reaches 25 GW of capacity by 2020 (17 GW of this being offshore) and 49 GW by 2032 (37 GW of this being offshore).

  - Other renewables excluding wind and including hydro, biomass and marine show an increase on current levels of 1.3 GW to 2020 and 2.9 GW over the full period to 2032.

  - Gas generation increases overall over the full period showing a 3.3 GW increase between 2012 and 2020 and a further 3 GW by 2032, resulting in an overall increase of 6.3 GW.

  - The coal-fired decreases dramatically over the period to 2032, with the existing 25 GW decreasing to 18 GW by 2020 and to 12 GW by 2032.

  - Carbon Capture and Storage (CCS) assumptions within this scenario show the introduction of this technology into the generation capacity mix from 2025 onwards with a total of 1.2 GW of CCGT plant fitted with CCS by the end of the period in 2032.

  - Nuclear power increases by a total of approximately 5 GW over the period taking the total nuclear generating capacity to 14.7 GW in 2032.

  - The existing level of renewables at 2012 in this scenario is 8.5% which will rise to 28.5% in 2020 and finally increasing to 41.5% in 2032.

- Accelerated Growth. It shows a much bigger increase in renewable generation than Gone Green and Slow Progression. The key changes of this scenario are shown below [47]:

- Wind generation increases steeply in this scenario and reaches 33 GW by 2020 and 64 GW by 2032 showing a total increase over the period of 59 GW.

- The coal-fired shows a net decrease over the period to 2032 of approximately 12 GW, the total coal capacity in 2020 is 20 GW with the total decreasing to 12 GW in 2030 but rising slightly again by 2032 as new CCS capacity comes on line.

- Nuclear power decreases over the period to 2020 by 1 GW, however increases over the full period to 2032 by a total of 8 GW, with the introduction of new nuclear plant.

- Other renewables which include marine, hydro and biomass also increase steeply over the period to 2032 showing a total generating capacity increase of approximately 6 GW, taking the total installed capacity to 7.7 GW.

- With Accelerated Growth being the scenario with the most rapid buildup of renewables the percentage level of installed renewable capacity in 2020 is 34% which increases to 46% in 2032.

3.2.3 Power Losses

Another factor that is related to carbon emission in power sector is the Power Losses. Power losses represent the fraction of energy lost caused by resistance in the electric network. Practically, additional energy needs to be produced to offset these losses so that the electricity supply is balanced. For example, a 100 mile 765 kV line carrying 1000 MW of energy to customer could have losses of 1.1% [58] and extra 1.1% electricity has to be produced on the generation side to balance these losses. Extra electricity production means extra combustion of fossil fuels, and extra carbon emissions emitted. Therefore, estimating Average Emissions Factor should take the Power Losses into consideration so as to enable estimation closer to the practicality.

3.2.4 Indirect Carbon Emissions

It is now widely recognized that GHG emissions resulting from the use of a particular energy technology need to be quantified over all stages of the technology and its fuel life-cycle [59]. Emissions from power plant operation are referred to as direct. Emissions in other processes such as fuel exploration, fuel transport, and waste management are categorized as indirect. The cumulative emission from a generator includes not only the direct, but also the indirect. Without considering the indirect effects, Average Emissions Factor might be underestimated. For example, advanced gas-fired power plants are estimated to emit just under 400g CO_2 eq/kWh as direct carbon emissions, with approximately 60g CO_2 eq/kWh as non-direct emissions [60].

For the CCGT unit, significant indirect emissions exist, which are mainly from gas processing, venting wells, pipeline operation (mainly compressors) and system leakage in transportation and handling. In the consulted literature, indirect carbon emissions from gas-fired plants lie from 15.27% to 28.07% of the total cumulative emissions [61]. For the coal-fired power plant, indirect carbon emissions could account for 5.56% to 28.00% of the total emissions [59]. For the oil-fired unit, significant indirect emissions arise mainly at the stages of oil transport, refinery, exploration and extraction, which are in the range of 5.41% to 13.58% of the total emissions [59].

3.3 New Model of Estimating AEF

Based on the above four aspects of discussion, a model of estimating Average Emissions Factor in power sector is given as:

$$AEF = \left(1 + PLoss\%\right) \times \sum_{i=1}^{N} P_i \, CE_i \, Id_i \qquad (3\text{-}4)$$

Where *PLoss*% is the active power loss of the electric network, described as a percentage of the total demand; CE_i is carbon efficiency of specific generator operating in the system; Id_i is the indirect factor of carbon emission; P_i is the percentage of energy production for specific generation technology (energy mix). *N* is the number of generation technologies.

3.3.1 Identification of Model Parameters

Before using the above model to assess Average Emissions Factor in power sector, the first step is to identify the parameters of this model. Basically, there are four variables incorporated in the model. Energy mix, for which P_i represents, is to be defined as input as data of energy mix from history to future scenarios is generally available. The other three variables are defined as parameters of the model. However, values of these parameters should be selected very carefully, as their values determine the output of the model and affect results of AEF to a large extent.

In order to solve this parameter selecting problem, Genetic Algorithm (GA) is used in this thesis to find the optimal parameters for the model. Basically, the parameters are optimized by minimizing the differences between outputs of the model (Results of AEF when feeding historical data of energy mixes into model) and the historical data (AEFs published by the government, referring to Chapter 2 Table 2-3). Mathematically, the optimization process can be formulated as:

$$\begin{cases} \min\left\{\sum_{i=1}^{n}\left(AEF_i - AEF_i^*\right)^2\right\} \\ AEF = f\left(x, y\right) \\ x = \left\{PLoss\%,\ CE,\ Id\right\} \\ y = \left\{P\right\} \end{cases} \tag{3-5}$$

Where AEF_i^* is the historical Average Emissions Factor estimated by government based on the accounting model, and AEF_i is the output of the model based on historical energy mixes; *n* represents the number of years. AEF_i is determined by two components; one is y_i (historical data of energy mix), the other is x_i which consists of three components (carbon efficiency of specific generator, power losses, and indirect emissions). So the objective is to find the optimal x_i so that the objection function – squared error, is minimized. And the optimization technique used is Genetic Algorithm.

Genetic Algorithm is a class of evolutionary algorithms (EA), which generate solutions to optimization problems using techniques inspired by natural evolution. However, discussion of optimization technique is outside the focus of this thesis and more of its details can refer to [61-63].

Constraints imposed on the optimization are the need to maintain selected parameter within the range outlined in chapter 3.2, which can be summarized as:

$$\begin{cases} F_l \le F_i \le F_u \\ Id_l \le Id_i \le Id_u \\ PLoss\%_l \le PLoss\%_i \le PLoss\%_u \end{cases} \tag{3-6}$$

3.3.2 Application of the Model

As soon as the parameters are optimized and selected, the proposed model is ready to estimate the Average Emissions Factor for future scenarios, or some other scenario wherever needed. Its input is the energy mix of electricity system and output is the estimations of AEFs.

Practically, many efforts have been made to find out the best energy mix in power sector. And this proposed model is compatible with these researches. As soon as a scenario of energy mix is obtained, the reverent AEFs can be estimated by the proposed model.

3.4 Case Study I: Estimating AEF in GB

A case study of the proposed AEF method is carried out in British electricity system. The model is firstly applied with the historical data of the accounted Average Emissions Factor, so that optimal parameters of representing the past can be found. The model is then applied to three future energy scenarios (Slow Progression, Gone Green and Accelerated Growth) to project the AFEs of the following two decades until 2032.

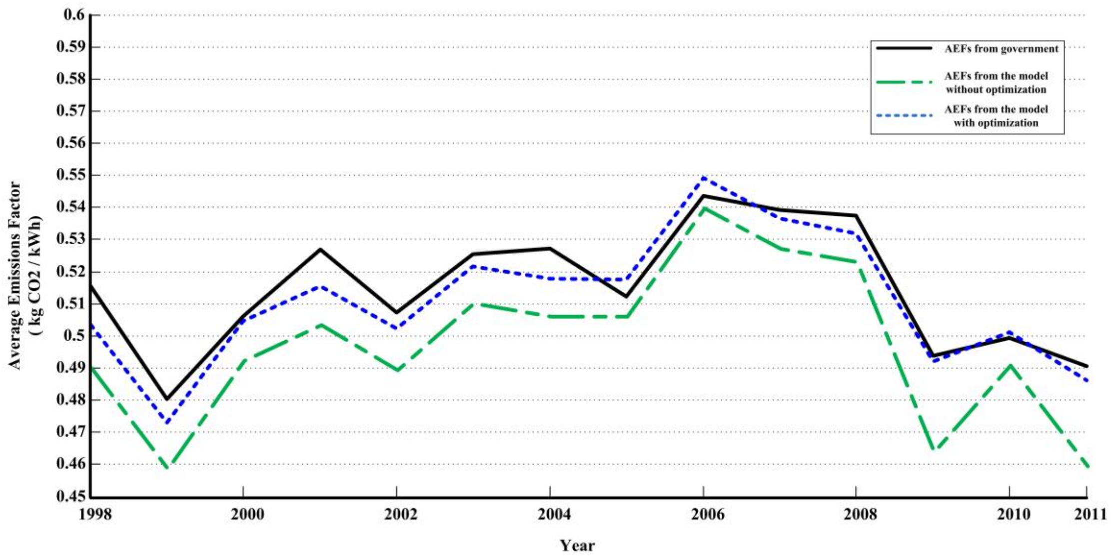

Figure 3-4 Average Emissions Factors from 1998 to 2011

Figure 3-4 is a comparison between the model's AEFs and the AEFs by the accounted model. AEFs without optimization means the parameters are not optimized by genetic algorithm. Those non-optimized parameters are based on the operation data of GB system of year 2010 (referred to [47]), which includes 7.88% of power losses, 0.90 kg CO_2/kWh of emission rate for coal-fired power plant and 0.405 kg CO_2/kWh for CCGT unit. They are also parameters in the range of constraints. However, it is clear in Figure 3-4 that, if the parameters are not optimized with the technique mentioned above, the correlation between the model's results and the actual AEFS is much worse. Such a comparison illustrates the effectiveness of the proposed technique. It also enhances the argument that parameters of the model need to be optimized with the historical data, as a better representative of the past could be a better estimator for the future scenario.

Table 3-1 Optimized parameters of CE_i

CE_i (kg CO_2/kWh)					
	Coal-fired	CCGT	Oil-fired	Pump Storage	Others
Optimized	0.8166	0.3211	0.9179	0.7124	0
Non-optimized	0.9000	0.4050	0.9500	0.6933	0

Table 3-2 Optimized parameters of Indirect and Power losses

	Id_i				PLosses%
	Coal-fired	Oil-fired	CCGT	Pump Storage	7.55%
Optimized	1.1952	1.1723	1.1275	1	
Non-optimized	1.2800	1.1300	1.2800	1	7.30%

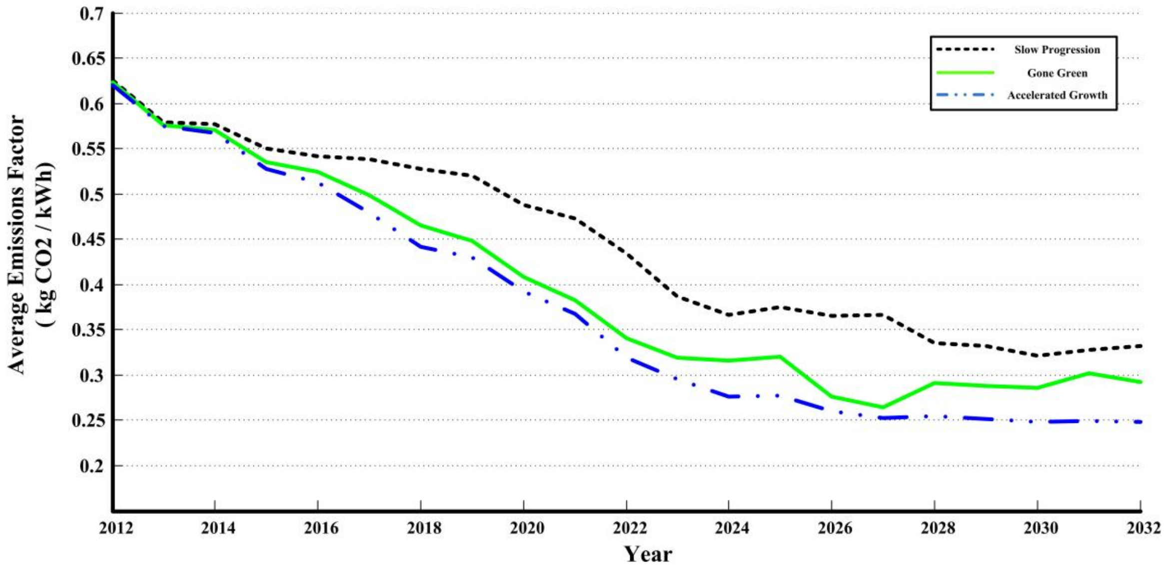

Figure 3-5 AEFs from 2012 to 2032 – with non-optimized parameters

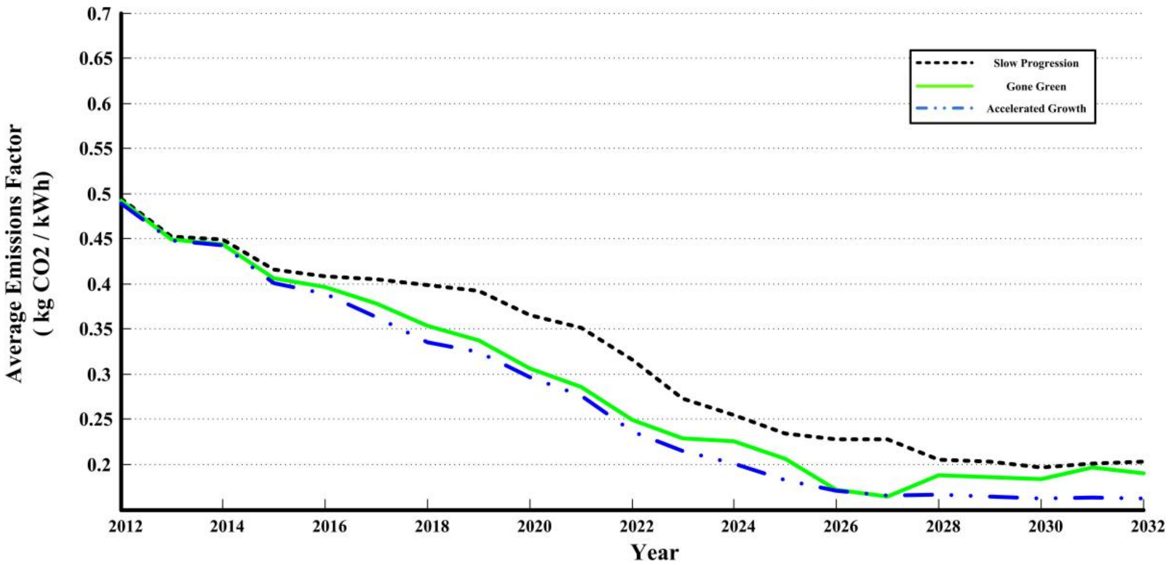

Figure 3-6 AEFs from 2012 to 2032 – with optimized parameters

As soon as the parameters are optimized, the model can be used to estimate the three future scenarios in GB. Figure 3-6 shows the projection of AEFs until 2032. As shown in the figure, the Accelerated Growth scenario yields cleanest carbon footprint than the other two scenarios, as it has the more emphasis on renewable energy than Gone Green and Slow Progression. According to the Accelerated Growth Energy Mix, the carbon footprint of power sector will be decreased by 68 per cent by 2032, compared with the 2012 level, 10 per cent further than the Slow Progression scenario. And this 10-percent decrease in carbon footprint is achieved by an extra 16% increase in the level of renewable generation, 46% of renewables by 2032 for the Accelerated Growth against 30% by 2032 for the Slow Progression. Approximately, 1% of increase in renewable generation is leading to 0.7% of decrease in carbon footprint in this study.

3.5 Case Study II: Estimating AEF in US and China

In 2010, 56% of US' Energy Mix was made of the coal-fired power plant, 16 per cent was made of natural gas, and 17 per cent was made of nuclear power. Only around 10 per cent of the mix was made of renewable energy, including 9 per cent of hydro power. More details of US's electricity system can be referred to [14].

Table 3-3 Energy mix of GB, US and China

	Gas	Coal	Nuclear	Wind	Hydro	Oil
GB	36%	35%	13%	7%	4%	5%
US	16%	56%	17%	1%	9%	1%
China	<1%	81%	2%	<1%	17%	<1%

As to China, majority of the electricity was generated by coal-fired power plants in 2010, around 81 per cent. Unlike US and GB, China has very little emphasis on gas-fired technology, which was less than 1 per cent in its Energy Mix of 2010. Hydroelectric is the second-largest source, accounting for 17% of the country's total energy consumption. While efforts has been making to diversify its energy supplies, nuclear power and wind energy still account for relatively small shares of China's energy consumption mix, just 2% for nuclear and less than 1% for wind [10].

As mentioned previously, parameters of the model need to be properly chosen before estimating Average Emissions Factors. Given the unavailability of historical data of Chinese and American electricity system, optimized parameters by the British system are still used to estimate AEFs of US and China. An estimation error is possible as those parameters might not represent the situation of US and China very well. However, electricity system performance as whole might not be the same among the three countries. Individual generation technology's performance should be quite similar among them. Also, the parameters used are within the range of technical constraints discussed previously. They should be plausible and valid values for estimating AEFs in US and China, although they are not the optimal ones.

Table 3-4 Comparisons of AEF among the GB, the US and China

	AEF (kg/kWh)	Coal	Gas	Oil
GB	0.4993	59.59%	30.85%	9.55%
US	0.6326	85.63%	12.67%	1.71%
China	0.7762	99.99%	< 0.01%	< 0.01%

For every of 1 kWh electricity used in the GB, around 0.4993 kg carbon emission had to be emitted into the environment in 2010 (59.59% made in the coal-fired plant, 30.85% made in the gas-fired plant and 9.55% made in the oil-fired plant). The AEF in the US was slightly higher than in the GB, as it used more coal-fired plants to generate electricity. However, China's AEF has been the worst case in this study. For every 1 kWh of electricity, 0.7762 kg of carbon emissions is made. This is because electricity generation in China almost entirely relies on the coal-fired plant and the coal-fired is the most polluting technology.

3.6 Chapter Summary

In this chapter, a novel model of calculating AEFs is proposed to assess the carbon footprint of electricity consumption. British electricity system is used to test the validity of this approach. Three future scenarios are used to project GB's AEF until 2032. AEFs of China and US are also assessed to analyze the current footprint levels of different countries. Based on the studies, conclusions can be summarized as:

- The proposed method is effective in estimating Average Emissions Factors over a long-time framework. Its estimations for AEFs can be improved by training the parameters of the model with the historical data.

- Estimations by the proposed model show that the carbon footprint of power sector will be decreased by 68 per cent by 2032 according to the Accelerated Growth Energy Mix, and decreased by 58 per cent by 2032 according to the Slow Progression scenario. Approximately, 1% of increase in renewable generation is leading to 0.7% of decrease in carbon footprint in this study.

- Comparisons of AEFs among GB, US and China show that the GB is leading the way in power sector on combating climate change. The carbon footprint of GB's power sector is cleanest among the three countries, due to its less relying on coal.

Chapter 4

Marginal Emissions Factor with Technical Constraint

THIS chapter improves the merit order method by considering the ramp-rate constraints in MEF estimation. Sensitivity analysis of MEF to different fuel prices is also analysed.

4.1 Introduction

The Average Emissions Factor is efficient for the purpose of calculating carbon footprint in power sector. However, it is an overall estimation of the whole system and it is inadequate for assessing marginal effects. Demand response is a marginal change. If there is a demand response taking place, it does not trigger all the generators in the system to response proportionally. Only part of the generators would be triggered to take response and others would remain nearly unchanged. This is the main reason why Marginal Emissions Factor is needed to evaluate the marginal change of carbon emission due to a change in demand.

In this chapter, two main merit order approaches of estimating MEF (utilization-level-based and fuel-cost-based) are applied to two scenarios of British electricity system (typical winter demand, and typical summer demand) to illustrate the differences between AEF and MEF in GB. Moreover, the MEF assessment is further improved by considering the impacts of ramp-rate constraint of generators as it is not plausible to expect some power plants like the coal-fired to ramp up and down very quickly. On the other hand, sensitivity analysis of MEFs to a few scenarios of fuel price is done at the end of this chapter to see how MEFs might change with different prices.

4.2 Necessity of Considering Ramp-rate Constraint

Studies of assessing MEFs with merit order approach have been trying to identify the marginal generators in the system and calculate marginal carbon emissions change due to a demand response. Existing methodologies of assessing MEF identify the marginal plants either by cost-based order whereby power plants are activated according to minimal specific cost targets, or by utilization-based order whereby the generating plant is ranked according to its available capacity to give an ordered generators' response.

Assuming a merit order of response is a plausible way of assessing the Marginal Emissions Factor. However, whether a generator is suitable for balancing demand response is determined, not only by its fuel cost or its utilization level, but also by its flexibility - ramp rate. Ramp rate is essentially the speed at which a generator can increase (ramp up) or decrease (ramp down) generation [64-66]. A generator responsible for taking demand response should be able to ramp its output up and down to offset the changes in demand.

Some generators have a very quick ramp rate. For example, a gas-fired generator might be able to ramp up to its maximum output in just 10-15 minutes, compared with hours that it takes a typical coal-fired power plant to reach its full output [64]; Hydro power also has high availability and quick ramp rates, always considered to be a balance source in power system. Therefore, the gas-fired plant and hydro plant are not considered to be constrained by the ramp rate in this research. They are assumed to be able to adjust their output as expected.

The coal-fired power plant has flexibility of changing output to meet the demand changes. That is reason why the coal-fired power plant is considered within the merit order of balancing demand response. Otherwise, it shouldn't be included in the order. The truth is that only flexible generators can be included in the order of response. Generators without flexibility, like nuclear plant, cannot be considered in this MEF assessment because it is an assessment of marginal effect by flexible generators.

Coal-fired power plant has some flexibility of balancing demand response, but its flexibility is limited and the limitation is the ramp rate. In other words, a coal-fired power plant might be triggered according to the assumed criteria to meet the demand response. But it might not be able to adjust its output as expected due to the ramp-rate constraint. It is not possible to consider a fast ramp-down of coal power generators, even under a cost based merit dispatch. Therefore, the impact of ramp rate should be included in the MEF estimation and generators with limited flexibility have to be constrained in this assessment.

4.3 Consideration of Fuel Prices

4.3.1 MEF Subject to Fuel Prices

In order to observe marginal effects of demand response, the fuel-cost-based approach identifies the expensive generators as the marginal plants for MEF estimation. However, there is an important assumption that can have a big impact on the results, namely the assumption of fuel prices.

The problem is that most of the MEFs' calculations are only based on one group of fuel prices (current or historical), lacking proper sensitivity analysis of fuel prices. For example, the fuel costs used in the paper [35-36] are the values listed in Table 3.1, which are based on fuel prices of year 2000, which is out-of-date since significant changes have taken place in fuel market.

Basically, fuel prices are the fundamental data used to decide the fuel-cost-base order. Results of MEFs are therefore very subject to the prices used. For example, if coal-fired electricity is very expensive due to a sky-high fuel price, the coal-fired power plants have to be working on the margin more often; otherwise the electricity bill is not affordable to the public. If the gas-fired electricity is very expensive, the CCGT units that use gas as fuel should be the marginal plants. The MEF would be wrongly estimated if improper generators are assumed to be on the margin.

Practically, very significant changes have taken place in the international fuel market during the past decade. The price changes of fossil fuel are likely to continue for the following decades. Therefore, there should be a proper sensitivity analysis, which shows how the results of MEFs might be affected by changing fuel prices.

4.3.2 Fuel Prices from the Past to the Future

The price of fossil fuel has steadily increased in the past two decades. The following three charts show how the real prices of coal, gas and oil have changed since 1987 [46]. The data presented here are given in terms of index number, which are a way of presenting proportionate changes in a common format, and their most common use is looking at changes over time [67]. The base year used here is year 1987, and other data are interpreted into percentage differences to get the index numbers.

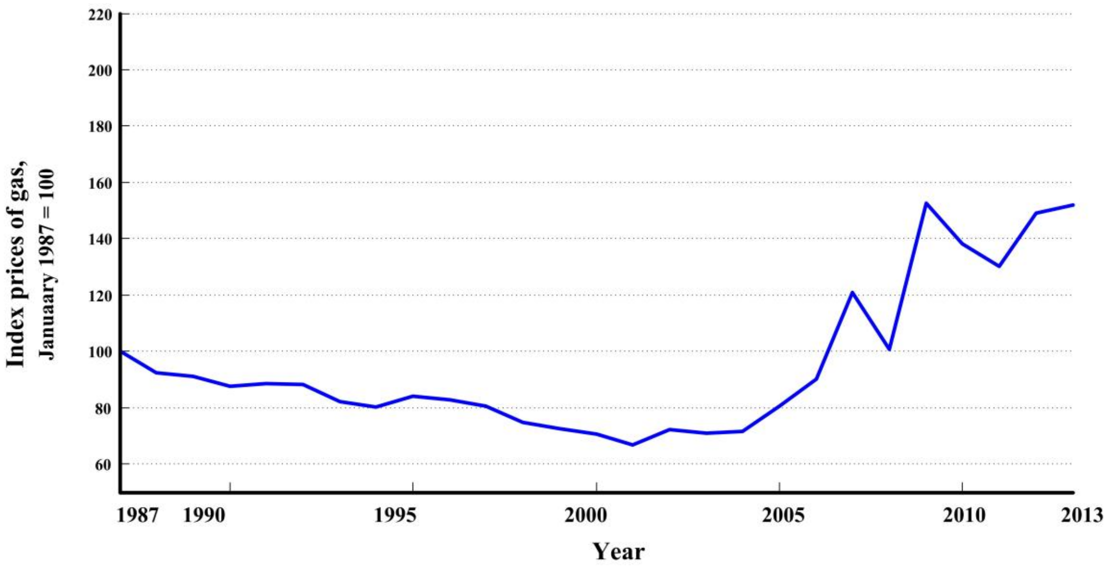

Figure 4-1 Index price of gas [46]

Gas prices fell gradually between 1987 and 2000, and in late 2000 prices were around one-third below compared with the 1987 level. The main reasons for the price falls up to 2000 were price controls set by the regulator and, latterly, the impact of competition [46]. However, after 2000 the price began to rise up consistently. The price grow between 2000 and 2005 was relatively smooth, but grew up very rapidly after 2005. It peaked at 2008 and the figures do reflect further price rises which are likely to come in for the following decades.

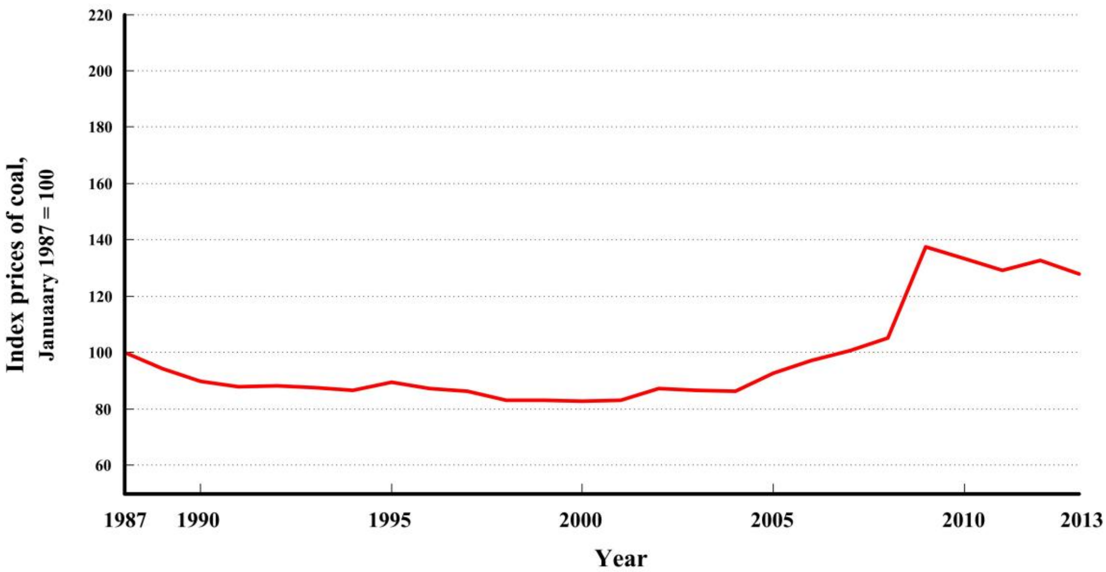

Figure 4-2 index price of coal [46]

Coal prices have shown a similar trend as the gas, down between from 1987 to 2000 and up afterwards. The coal prices were more stable than gas and fluctuations were much smaller. There were some increases in coal prices after 2005, but evidence does not reflect a big price increase in the near future.

Forecasting fossil fuel prices into the future is a challenging job, as the uncertainties of determining the prices are very difficult to manage. And those uncertainties such as economic growth and development of new technologies are generally very volatile. Therefore, this thesis is not going to forecast the fissile fuel prices. Instead, reliable projections of fuel prices from Department of Energy & Climate Change (DECC, British government) are to use in this thesis [68]. The key point for this study is to see how the MEFs might change over time with future price scenarios. DECC's projections of coal price and gas price are given in the following two figures.

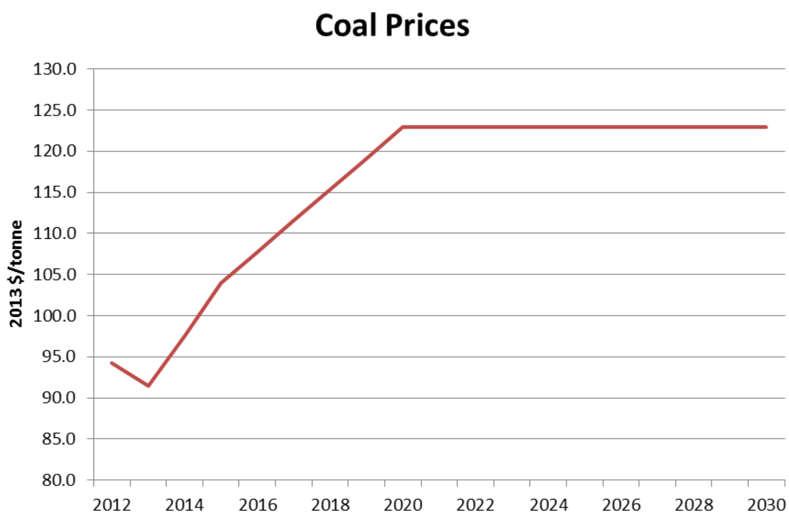

Figure 4-3 DECC's coal price projection [68]

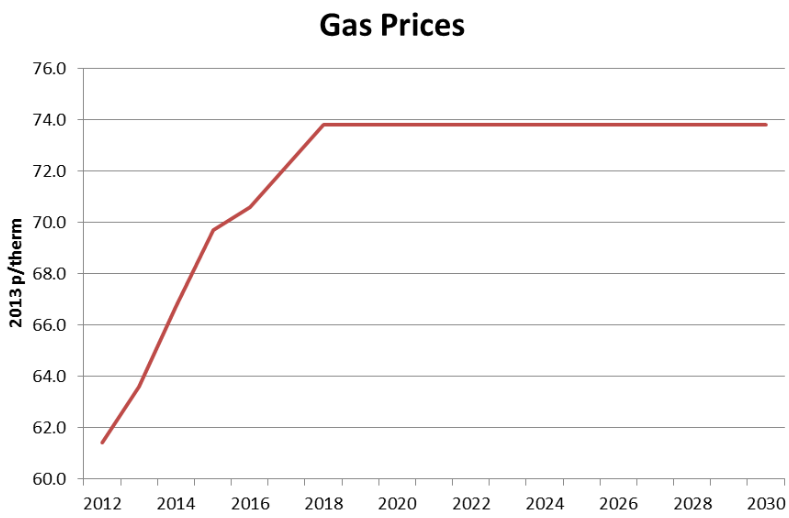

Figure 4-4 DECC's gas price projection [68]

4.4 Merit Order Model with Ramp-rate Constraint

To grasp the impacts of demand side on carbon emission, start-up criteria is needed to determine which plants have the priority to meet the demand change in a power system. Based on the assumption that generators with highest fuel costs are desirable for balancing demand response, the generating plants are ranked according to the following equation to dispatch:

$$Rank = \min\left\{FC_1, FC_2, \cdots, FC_i, \cdots, FC_N\right\} \tag{4-1}$$

Where, FC_i refers to fuel cost generator i. On the other hand, generators have ability to adjust their output to meet demand response. But the ability is not unlimited. It is constrained by ramp rate. Therefore, the impact of ramp rate should be included in the MEF estimation and generators' flexibility has to be constrained in this assessment, which can be summarized as:

$$\begin{cases} G_l \le G_i \le G_u \\ \Delta G_i \le \Delta G_{\max i} \end{cases} \tag{4-2}$$

G_i refers to the output of generator i, which should be within the range between maximum available output G_u and lowest allowed output G_l. The rate of change for each generator i should be limited by its own ramp rate ΔG_{max}. Flow chart of assessing MEFs with this proposed model can be summarized as:

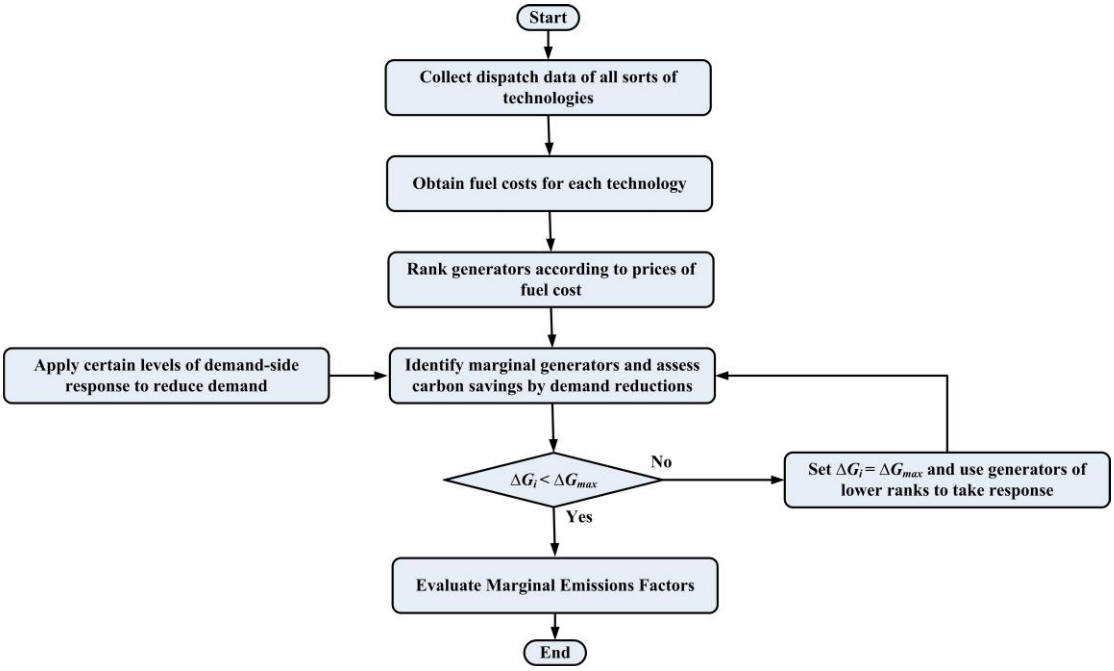

Figure 4-5 Flow chart of the new MEF approach with ramp-rate constraint

4.5 Assumptions

4.5.1 Scenarios Used for Demonstration

To set the comparisons of MEFs between the proposed method and other methods in an appropriate context, typical winter demand and typical summer demand in GB electricity system are used in this study.

Briefly, the British electricity system largely consists of three major groups of power plants: nuclear power plants (13%), Combined Cycle Gas Turbine (CCGT) plants (35%), and coal-fired units (35%). As a point of interest, Figure 4-6 and Figure 4-7 are given to show how demand was actually met by the generators' response that referred to the typical winter demand (Wednesday, 17/11/10) and typical summer demand (Thursday, 10/06/10) respectively [69].

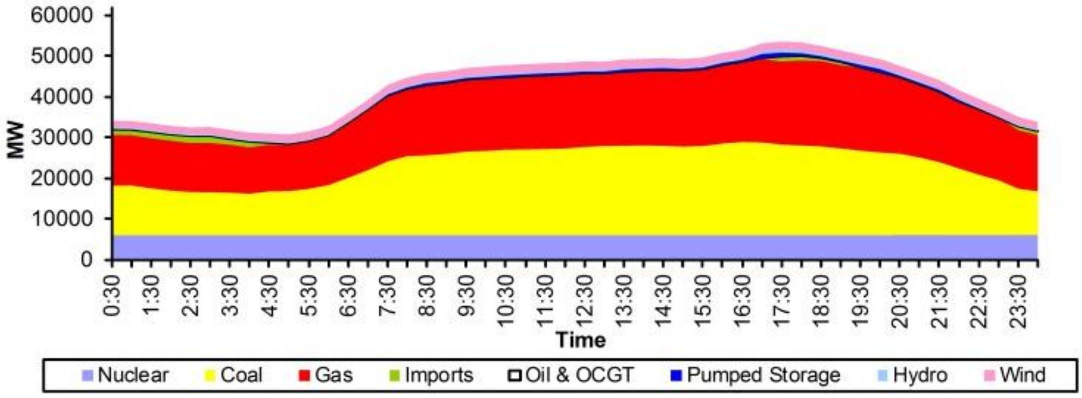

Figure 4-6 Typical Winter Demand: Wednesday, 17/11/2010 [69]

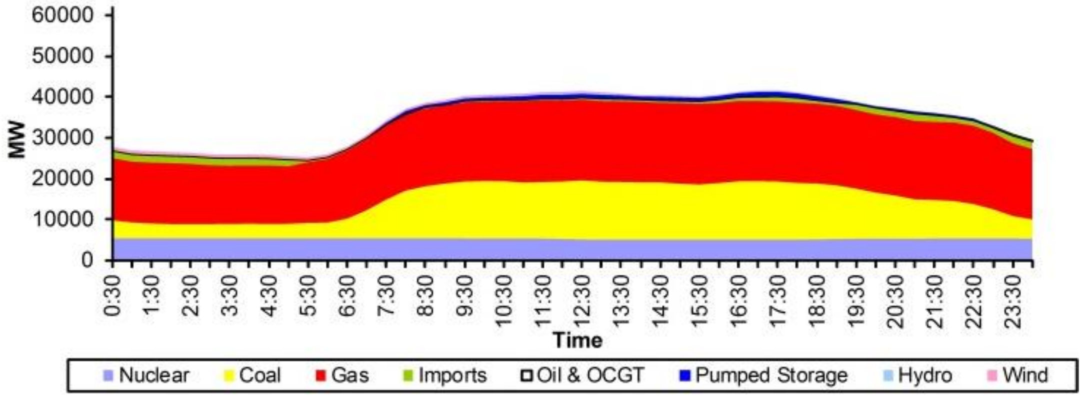

Figure 4-7 Typical Summer Demand: Thursday, 10/06/2010 [69]

4.5.2 Assumption of Demand Reduction

Electric power planners expect increased participation in demand response to decrease peak electric power demand by up to 5% over the next ten years [70]. The relationship between electricity demand reduction and carbon emission is considered to be central for low-carbon emission policy. It is clear that carbon savings per kWh are not the same with various demand reductions, as different reduction can trigger different selections of generators to take response. So the sensitivity of MEF to different level of demand reduction needs to be examined. In this study, three demand reductions are used to show the effects of different demand reductions on the MEFs: tiny reduction (1%), moderate reduction (5%) and mass reduction (10%). To figure out the MEFs might change with time, all hours of the day are assumed to experience reductions at these percentage levels.

4.5.3 Assumption of Ramp Rate

As mentioned in previous section, generators responsible for taking demand response need to ramp its output up and down within their own ramp rate. For every single generator, ramp rate is one of the basic properties that can be found in the generator's design menu. The general principle is to model each generator's ramp rate independently, but complexity can be reduced by modeling each generation technology as a group and then assuming a ramp rate to each group. In this study, the ramp rate is carefully selected by analyzing the dispatch profile of each technology and assuming the biggest change of the day to be ramp rate for this technology. For example, in the typical winter scenario, the maximum change of the coal-fired technology was 2145.92 MW that happened in half an hour. So the upper constraint of ramp rate for the coal-fired in the typical winter scenario is chosen as 4292 MW/hour. Furthermore, due to the reason that the power industry has begun to improve the flexibility of coal-fired technology and it is possible that the coal-fired will run more flexibly in future [71-73], two additional ramp rate scenarios (-5% and +5%) are also considered to see how MEFs can be changed with the different ramping ability.

4.6 Case Study I: Typical Winter Scenario

In order to have a better understanding of marginal Carbon Emission Factors, two typical merit-orders approaches (the fuel-cost-based and the utilization-based) are selected to weigh up their merits and drawbacks in MEF assessment. The new MEF approach with consideration of ramp-rate constraint is also applied in the scenario to make a comparison. Fossil fuel prices in this section is based on the data from [35] and sensitivity analysis of MEFs to fuel prices is done in the section following.

4.6.1 Impacts of Ramp Rate

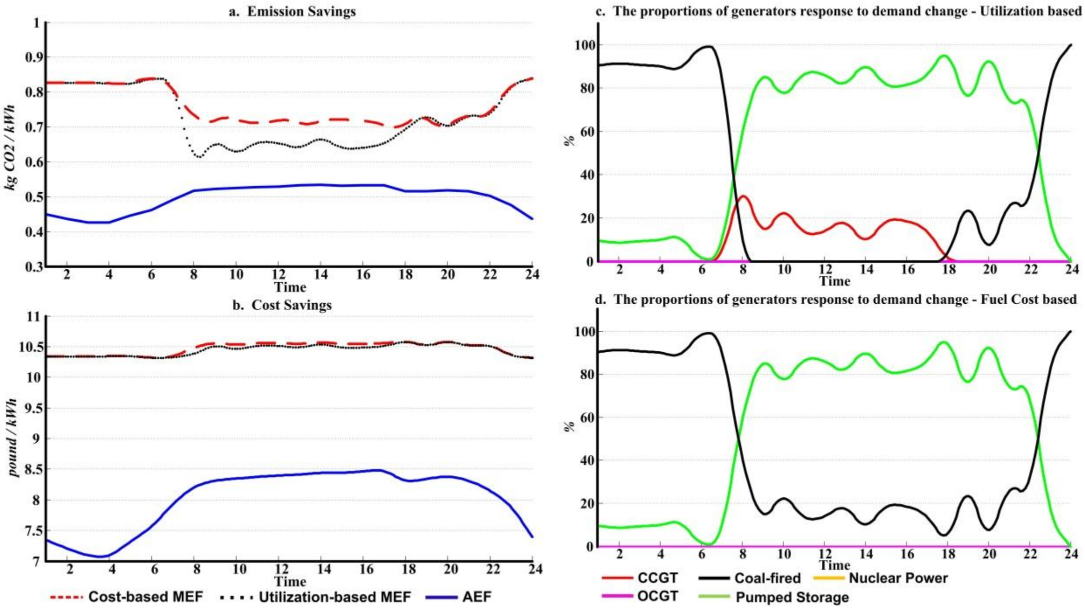

Figure 4-8 Typical winter demand, 1% demand reduction

First of all, MEFs without technical constraint are estimated in this scenario (Figure 4-8). The results in Figure 4-8.a show that, if 1% uniform reduction is applied, the utilization-based MEFs are very close to the fuel-cost-based MEFs in off-peak hours of typical winter demand. The MEFs of off-peak hours are around 50% higher than the system average factors - AEF.

In peak hours, the utilization-based MEF is slightly smaller than the cost-based MEF, but both of them are bigger than the AEF. The results in Figure 4-8.b is a comparison of fuel cost savings among these three factors. The cost savings shown indicate the fuel cost that can be saved when the system demand is reduced. It can be seen that fuel cost savings of the utilization-based assumption and cost-based assumption are very similar to each other when system demand reduction is considered to be 1%.

The reason for such similarity in cost estimation and difference in MEFs estimation is mainly because of the marginal generators assumed. Both the utilization-based order and the cost-based order assume around 80% of demand reductions are taken by pump units during the peak hours. However, the utilization-based order assume CCGT units take the rest 20 per cent of demand reduction, and the cost-based order assume the coal-fired plants are responsible for the rest 20 per cent (shown in Figure

4-8.c and Figure 4-8.d). Different assumptions lead to the small differences in the cost savings, as fuel costs for CCGT and the coal-fired plants are almost the same according to the provided data, 10.3174 pound / MWh for the coal-fired and 10.0192 pound / MWh for the CCGT. But cost-based MEFs are this much bigger, as carbon efficiency for the coal-fired (0.85 kg CO_2 / kWh) is much higher than the CCGT (0.40 kg CO_2 / kWh).

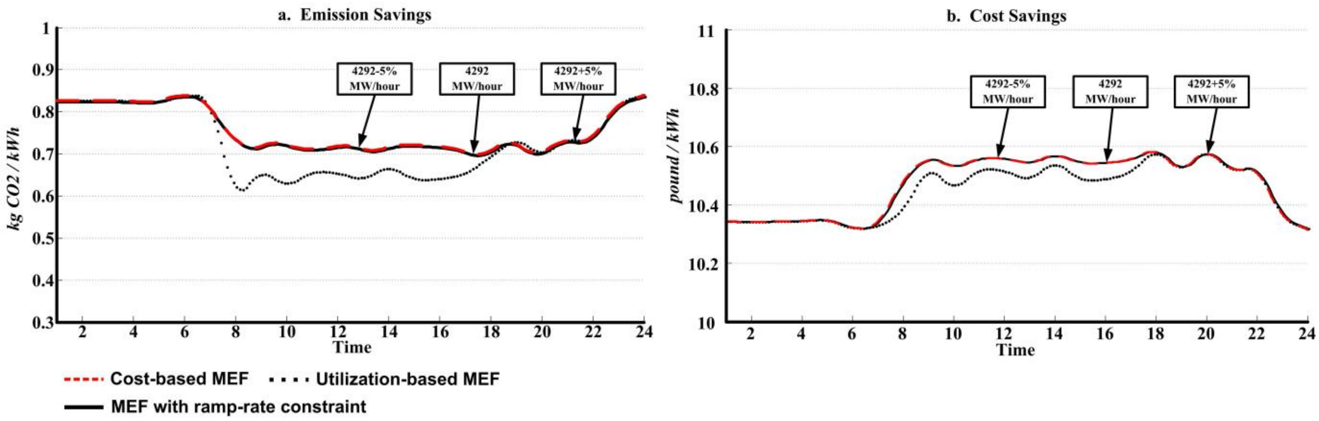

Figure 4-9 Typical winter demand, 1% reduction with ramp-rate constraint

The results in Figure 4-9 show the MEFs estimation with consideration of ramp-rate constraints. Because the demand reduction considered in this case is very tiny, restrained generators have enough ramping capability to balance such tiny change without changing the merit order. Therefore, the MEFs with ramp-rate constraint are the same as the fuel-cost-based MEF because they both expect the more expensive generators to take the response.

When the demand reduction is increased to 5 per cent (as shown in Figure 4-10), the cost-based MEF is nearly unchanged, but the utilization-based MEFs dip to 0.45 kg CO_2 / kWh during the peak hours (as shown in Figure 4-10.a). This is because the utilization-based approach assumes the CCGT units to take response (Figure 4-10.c). The utilization-based MEFs assume the CCGT units to be the marginal plants during the peak hours, which take response to 80 per cent of the 5% reduction. The cost-based MEFs assume the majority of demand change to be taken by the coal-fired plants (Figure 4-10.d). Therefore, during the peak time, the cost-based MEF is close to the coal-fired value (0.85 kg CO_2 / kWh), and the utilization-based MEF is close to the CCGT value (0.4 kg CO_2 / kWh). In terms of cost savings, the cost-based estimation is slightly higher than the utilization-based estimation during the peak hours (as shown in Figure 4-10.b).

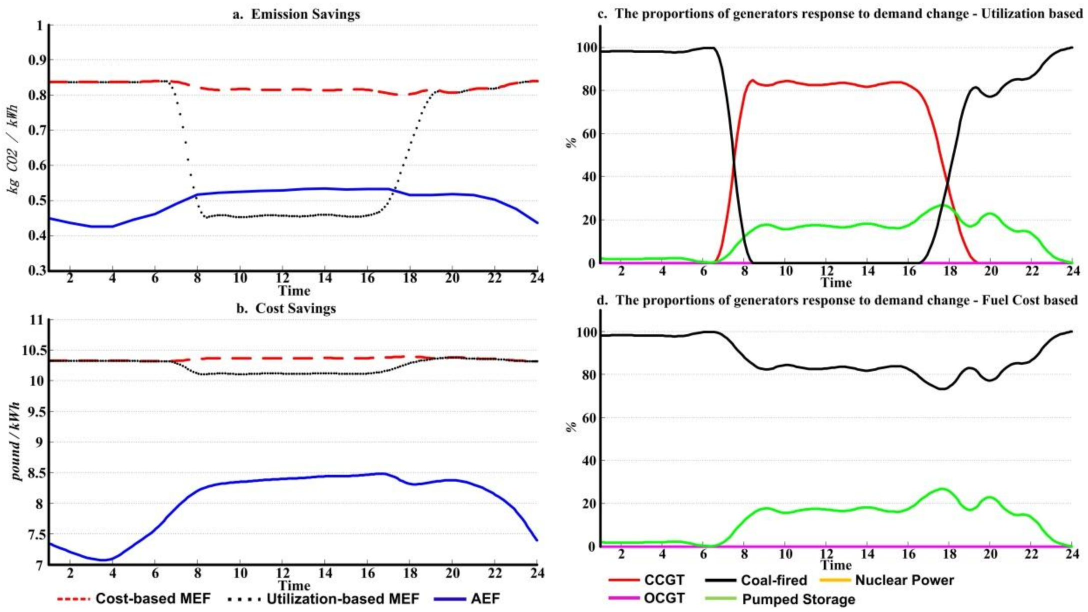

Figure 4-10 Typical winter demand, 5% demand reduction

However, if considerations of ramp-rate constraint are included in MEF estimation, the results become different. As can be seen in Figure 4-11, MEFs with constraints are lower than the original cost-based MEF when the ramp rates are set up to be 4292 MW/hour and 4077 MW/hour (4292-5%). The reason is the coal-fired generators being restrained.

The coal-fired power plant has limited flexibility of changing output to meet the demand changes. It is not possible to expect a fast ramp-down of coal power generators, even under a cost based merit dispatch. Therefore, when the demand reduction is bigger than the coal-fired plant’s ramping capability, the coal-fired is not able to take the whole reduction as expected. Part of the demand change has to be transferred to other generator that is the next in merit order. In this case, the demand changes, that are supposed to be totally taken by the coal-fired according to a cost based merit dispatch, are shared between the coal-fired and the CCGT units. The CCGT is a much cleaner technology than the coal-fired and the MEFs are thus lowered.

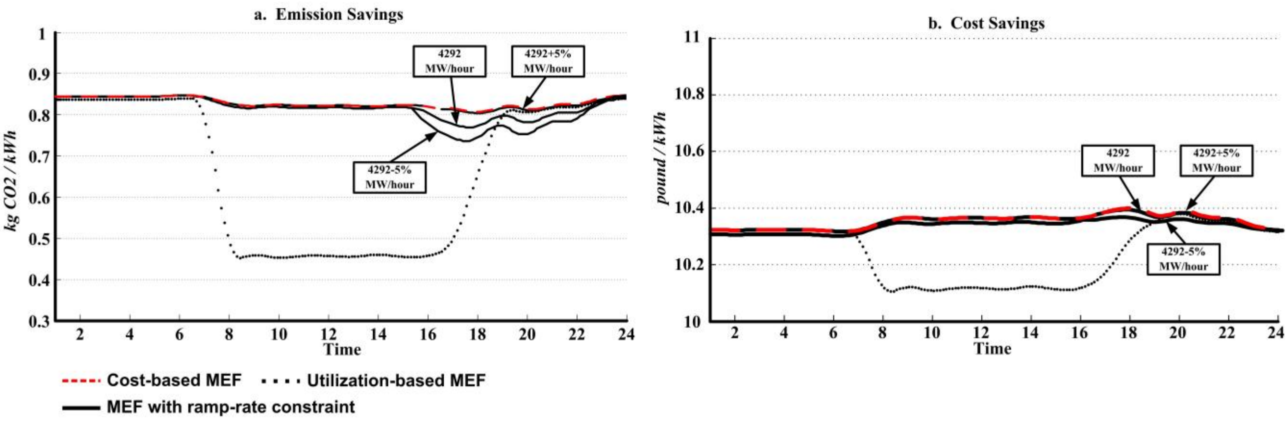

Figure 4-11 Typical winter demand, 5% reduction with ramp-rate constraint

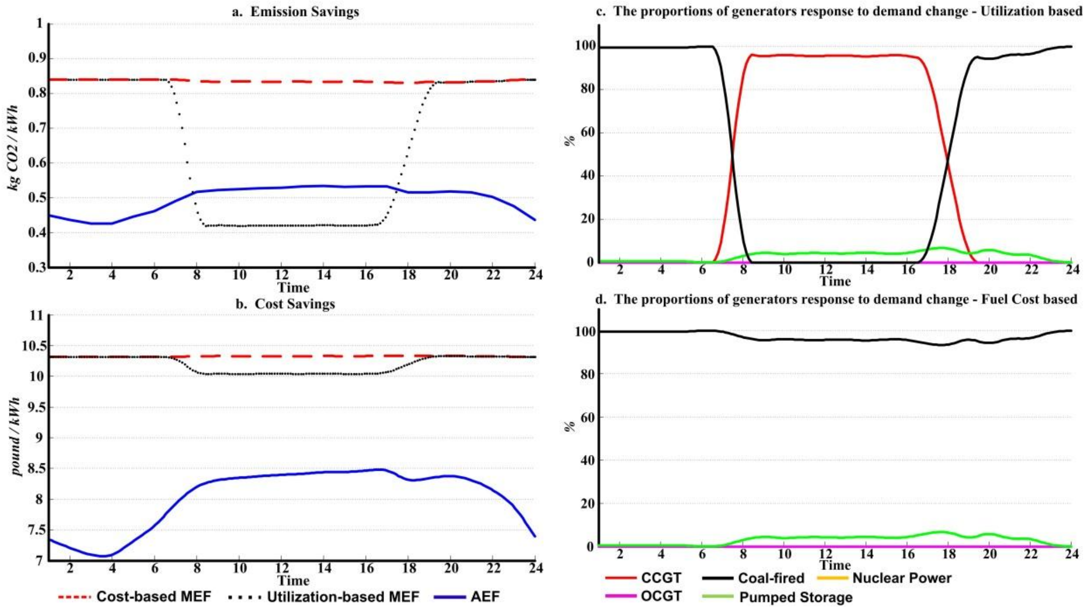

Figure 4-12 Typical winter demand, 10% demand reduction

If the demand reduced is increased up to 10% (Figure 4-12), both the cost-based MEFs and the utilization-based MEFs are almost unchanged compared with 5% reduction. However, if the ramp rates are considered (Figure 4-13), results of MEFs turn out to be very different. The MEFs with constraints are much lower than the fuel-cost-based MEFs, even under a cost based merit dispatch. This is due to more demand reduction being transferred to the CCGT units, as 10 per cent is a mass change and output of coal-fired plant is limited by its ramp rate. The coal-fired cannot experience a fast enough ramp down in this scenario, thus triggering the CCGT to take part of the reduction. Values of MEFs lie in the range between the coal-fired emissions rate and the CCGT's emissions rate.

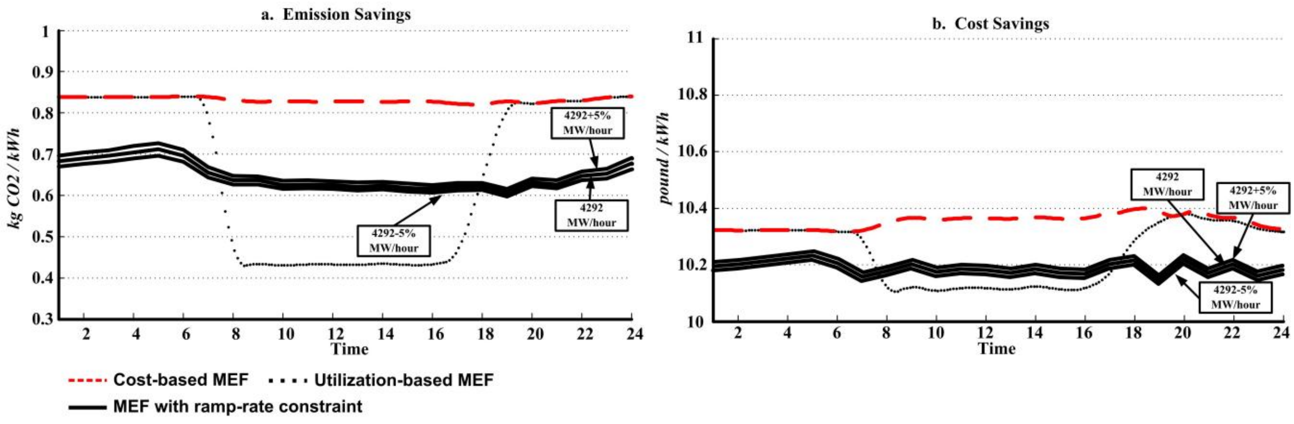

Figure 4-13 Typical winter demand, 10% reduction with ramp-rate constraint

From these three level of demand reductions (1%, 5%, and 10%), it can be seen that the differences between the cost-based MEF and the utilization-based MEF during the peak hours are mainly due to different marginal generators being assumed. The cost-based MEF considers pump units and the coal-fired plants to be responsible to demand reductions, while the utilization-based MEF considers pump units and the CCGT. The cost savings of these two MEFs are similar, but emissions savings indicate big differences.

When the demand reduction is small (1%), generators' ramp rate has little impact on the results of marginal carbon savings as the flexible generator has enough capability to balance the reduction. But if the demand reduction is significant, the ramp rate can have an impact on the MFEs' estimation and consideration of ramp-rate constraint becomes indispensible.

4.6.2 Different Fuel Prices

In order to see how MEFs might be affected by changing fuel prices, two more prices scenarios are used in this section, current fuel prices scenario and future fuel prices scenario.

The current fuel prices scenario is based on the data from DECC [86], which are more up-to-date than the previous scenario. Prices in current scenario can be summarized as: 73 £/MWh for the OCGT, 30 £/MWh for the coal-fired, 48 £/MWh for the CCGT and 5 £/MWh for the nuclear. The future fuel prices scenario considers the possible increases of fossil fuel prices, and then fuel prices are updated according to the projection. Prices in future scenario can be summarized as: 91 £/MWh for the OCGT, 39 £/MWh for the coal-fired, 60 £/MWh for the CCGT and 5 £/MWh for the nuclear. Prices in both two scenarios are then used to build up updated fuel-cost-based merit order and updated MEFs are thus estimated.

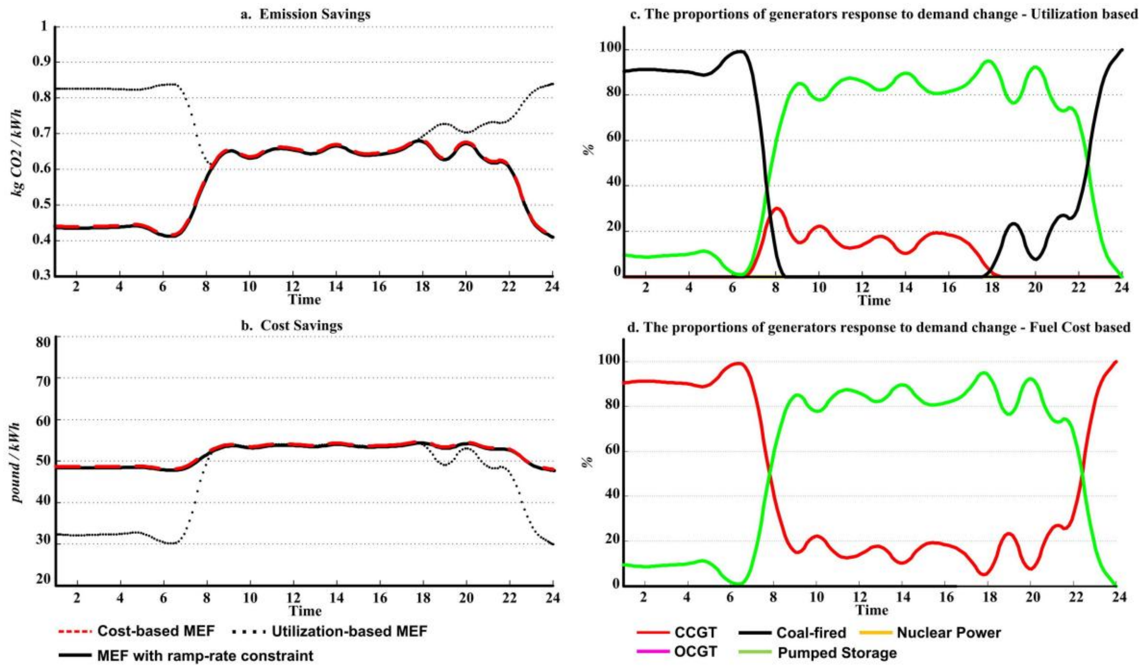

Figure 4-14 Typical winter demand, 1% reduction, current fuel prices

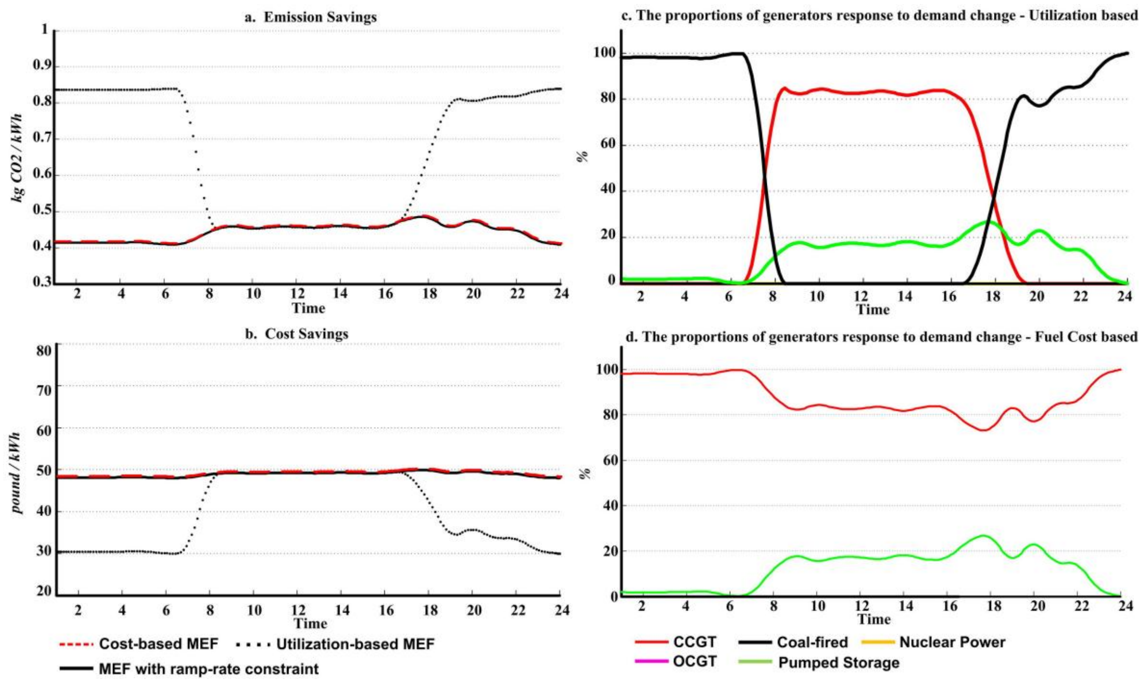

Figure 4-15 Typical winter demand, 5% reduction, current fuel prices

Results in Figure 4-14 show that increase in gas price has fundamentally change the dispatch order for MEFs estimation. The CCGT units taking place of the coal-fired are expected to become more active in responding demand, as the price of gas is more expensive than coal now. The coal-fired power plants are not expected to take any demand change at all, as coal is cheaper and cheaper generators need to stay in supplying electricity. The MEFs based on current fuel prices are much smaller than the MEFs based on past fuel prices, because CCGT is a much cleaner technology than coal.

Figure 4-15 and Figure 4-16 shown very similar results to Figure 4-14. It seems that the MEFs of 10% demand change are similar to those of 1% demand change. So a conclusion might be drawn that if MEFs estimation is based on fuel-cost merit order, the MEFs are not very subject to levels of demand changes.

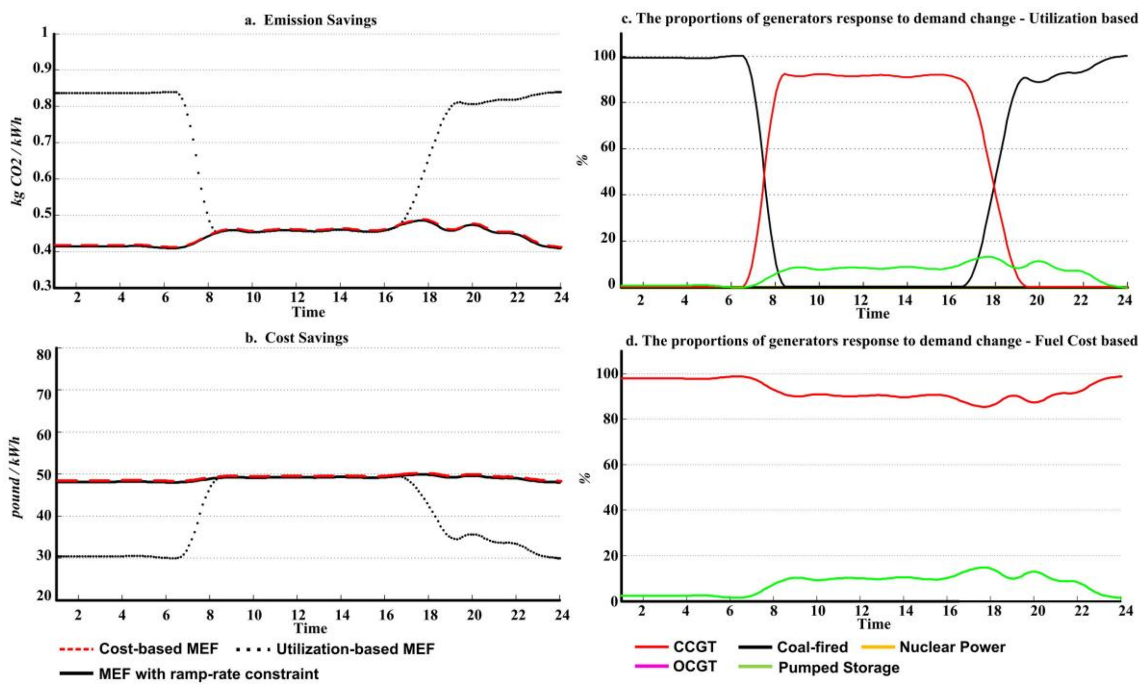

Figure 4-16 Typical winter demand, 10% reduction, current fuel prices

When the future fuel prices are used to set up the merit order, nothing is changed except the potential cost savings. As shown in Figure 4-17 to Figure 4-19, estimated MEFs are hardly changed and generators are taking response in the same way as in the current prices scenario. But the potential cost savings are higher than now because of the increase in fuel prices.

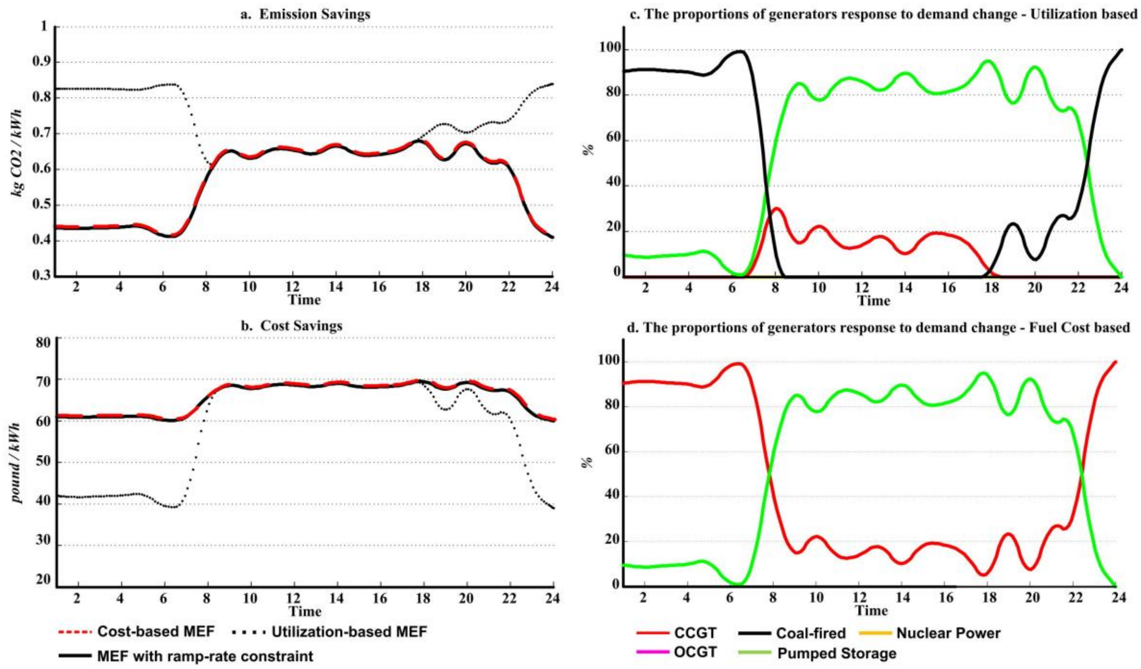

Figure 4-17 Typical winter demand, 1% reduction, future fuel prices

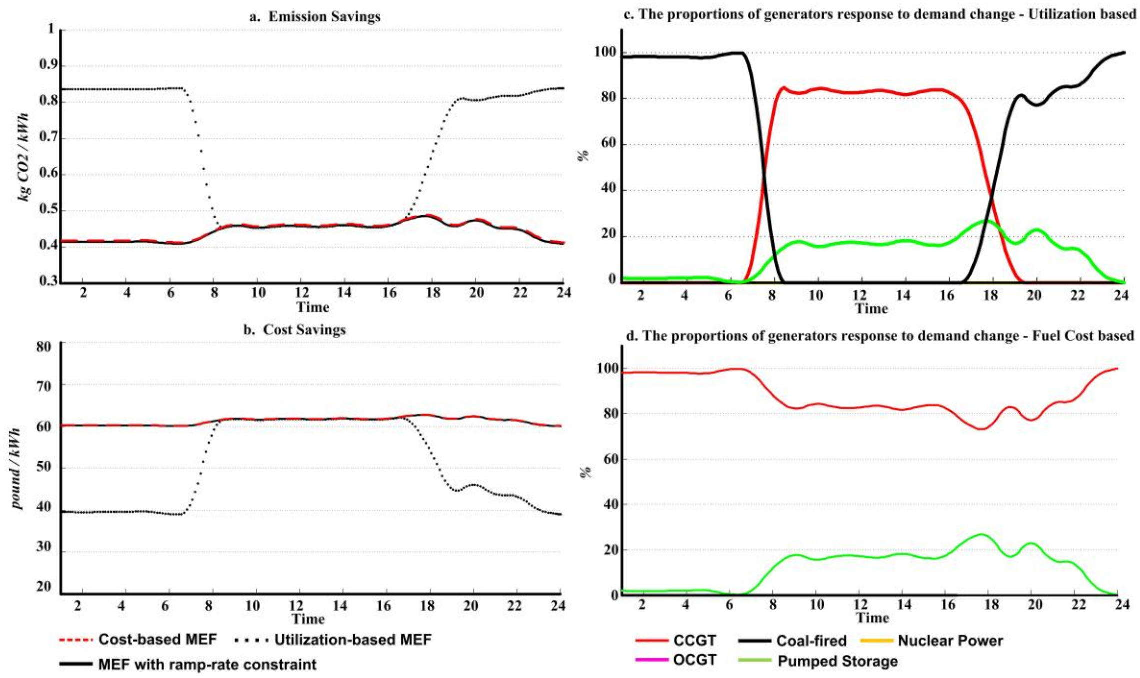

Figure 4-18 Typical winter demand, 5% reduction, future fuel prices

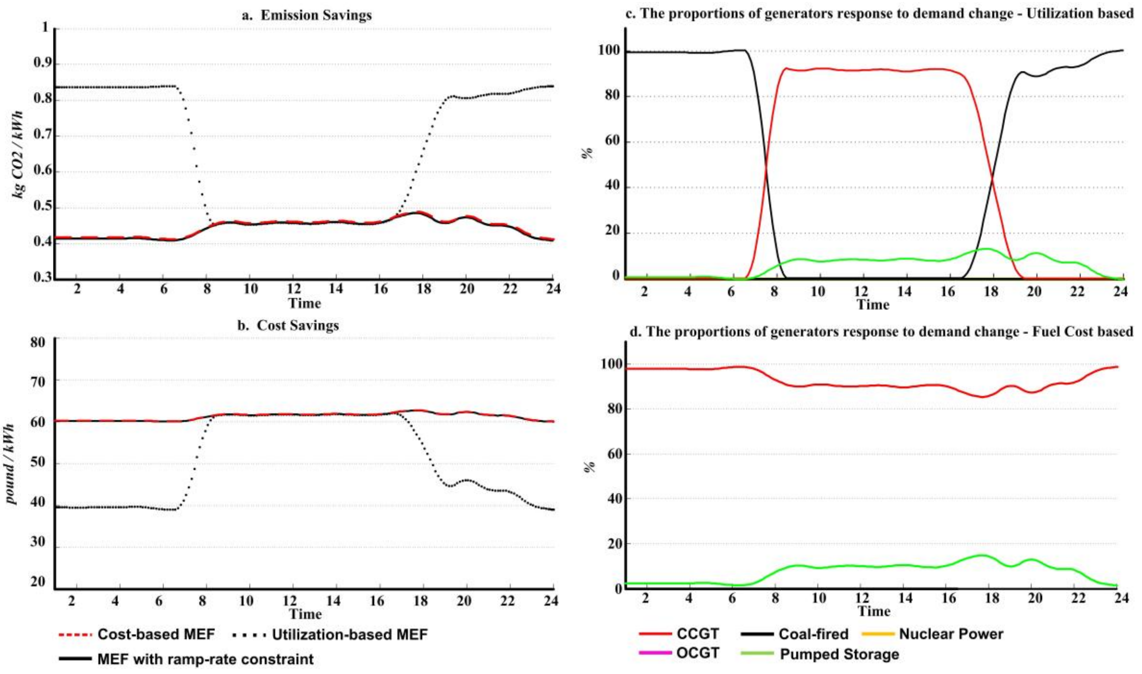

Figure 4-19 Typical winter demand, 10% reduction, future fuel prices

Based on these analyses, it can be seen that fuel-cost-based MEFs are significantly different between the past price scenario and the current price scenario. This is because gas price becomes more expensive than coal and the merit order is fundamentally changed. However, going from the current scenario to future scenario, the MEFs are hardly changed due to the factor that gas is and will be more expensive than coal. There is no chance for coal to be more expensive than gas in terms of fuel prices. The fuel-cost-based MEFs are subject to fuel prices but the order of dispatch will remain stable for a long period of time, which to some extent indicates the necessity of introducing carbon mechanism to make low-carbon technology more competitive in electricity generation.

On the other hand, in both current scenario and future scenario, the coal-fired power plants are not expected to take any demand response. It is true that the coal-fired unit is neither as flexible as the CCGT unit, nor as clean as the nuclear power. It is a generation technology with limited flexibility. Its flexibility, however limited it is, should not be ignored and discarded. Actually, the power industry has begun to take another look at how coal can be run more flexibly in future [71-73]. Based on this analysis, it can be seen that, if the coal-fired could be more flexible, the carbon savings by demand reduction would be much higher than expectation. If the limited flexibility of coal-fired power plant could be made use of, demand response would be much more effective in reducing carbon emissions.

4.7 Case Study II: Typical Summer Scenario

In typical summer scenario, the maximum change for the coal-fired technology was 5256.98 MW/hour, ramping up from 6852.99 MW to 9481.48 MW in half an hour. So the upper constraint of ramp rate for the coal-fired in typical winter scenario is chosen as 5256 MW/hour. Furthermore, two additional ramp rate scenarios (-5% and +5%) are also considered to see how MEFs can be changed with the different ramping ability. Fossil fuel prices is also based on the data from [35] and sensitivity analysis of MEFs to current and future fuel prices is done in the section following.

4.7.1 Impacts of Ramp Rate

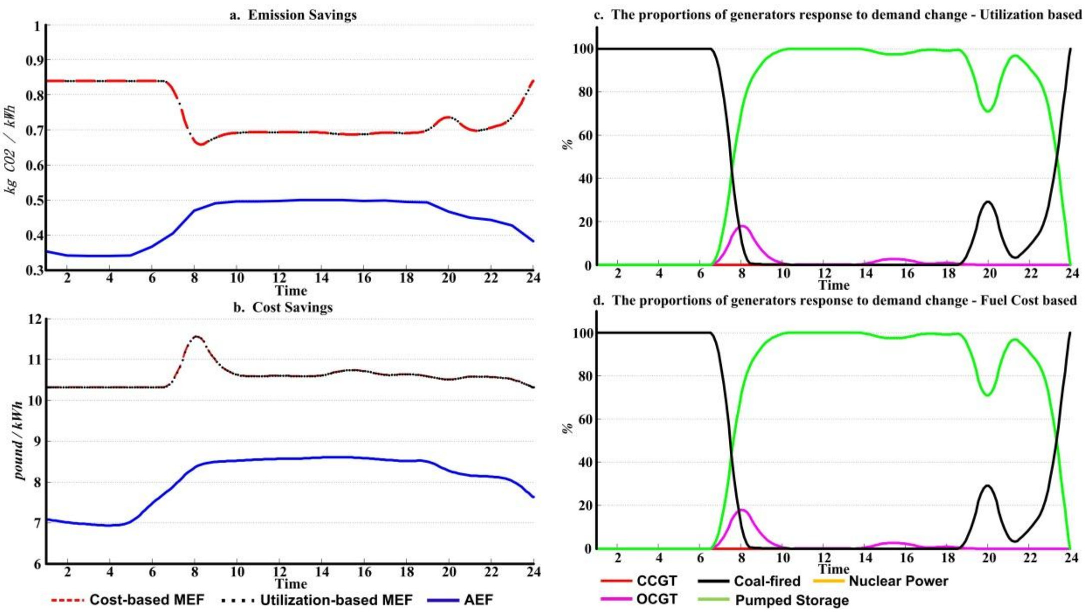

Figure 4-20 Typical summer demand, 1% demand reduction

First of all, MEFs without technical constraint are estimated (shown in Figure 4-20). In typical summer scenario, when all hours of the day are expected to experience reductions at 1% level, most of the demand changes in peak hours are taken by the pumped units (Figure 4-20). The utilization-based MEF and the cost-based MEF are the same throughout the day, holding MEF at around 0.85 kg CO_2 / kWh in off-peak hours and 0.70 kg CO_2 / kWh in peak hours. The AEFs are about 0.5 kg CO_2 / kWh, which are much lower than MEFs (shown in Figure 4-20.a). In terms of cost savings, the MEFs' rate (around 10.5 pound / MWh) are much bigger than AEFs' rate (around 8 pound / MWh), because the marginal plants are generally more expensive than the base-load plants.

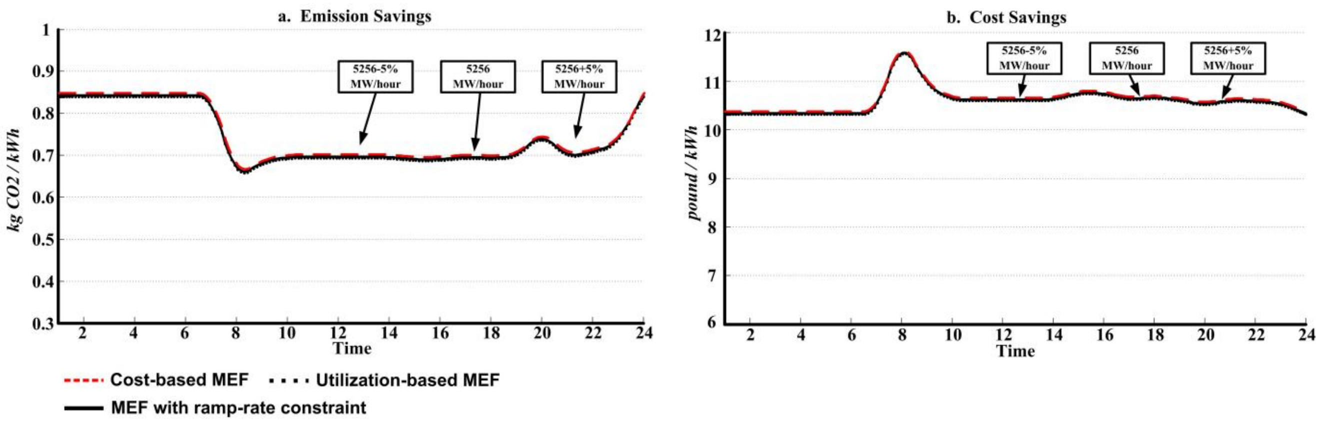

Figure 4-21 Typical summer demand, 1% reduction with ramp-rate constraint

The results in Figure 4-21 show the MEFs' estimation with consideration of ramp-rate constraints. It is clear that the MEFs with ramp-rate constraint are unchanged compared with those without constraints. It is because the flexibility of the marginal plants (the coal-fired) is enough to balance small demand change and ramp-rate constraints have little impact on MEFs in this case.

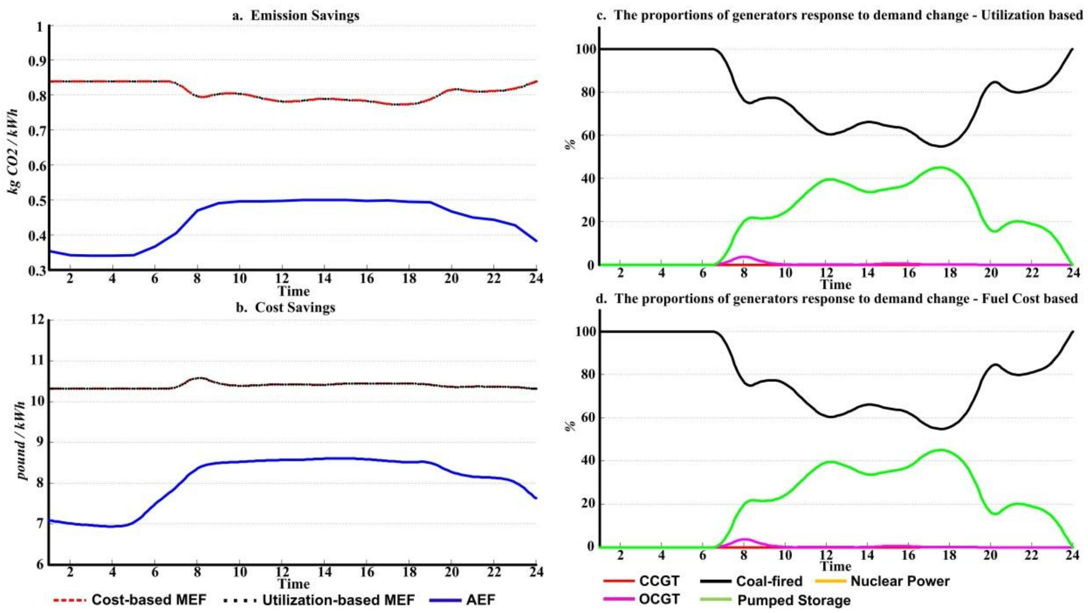

Figure 4-22 Typical summer demand, 5% demand reduction

When the demand reduction is increased up to 5% (Figure 4-22), the pumped units are still assumed to response first in peak hours for the both of the MEFs. However, given that pumped units working in the system are insufficient to meet demand changes; part of the reduction is taken by the coal-fired plants. As a result, MEFs in the peak hours are lifted to 0.85 kg CO_2 / kWh.

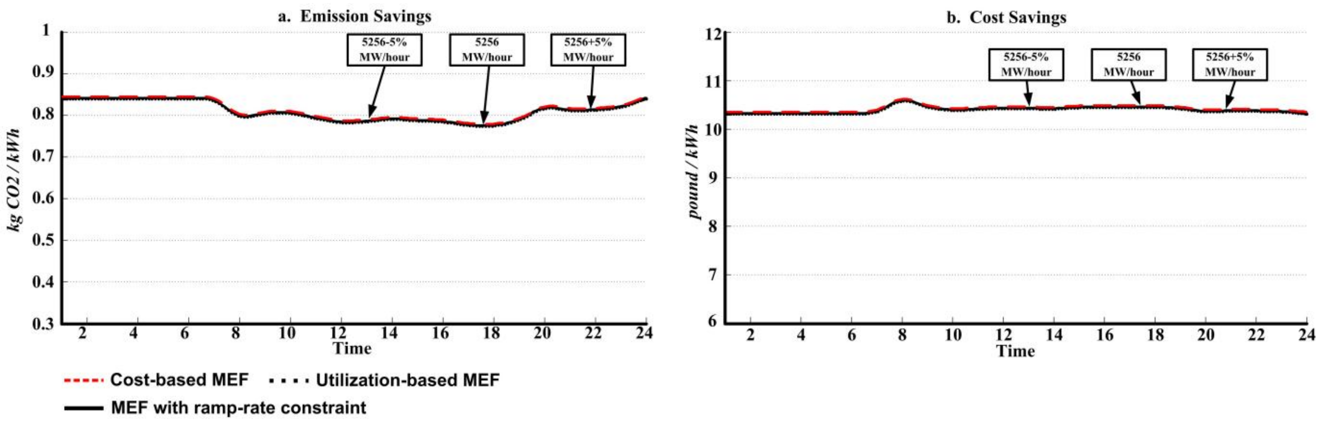

Figure 4-23 Typical summer demand, 5% reduction with ramp-rate constraint

When the demand reduction is increased up to 10% (Figure 4-24), more coal-fired plants are needed to response to demand changes. However, in off-peak hours, the coal-fired plants online are insufficient to meet the 10% reduction, thus triggering some CCGT units to take response. As shown in Figure 4-24c and Figure 4-24.d, around 25% of demand reductions are taken by the CCGT units during the off-peak hours.

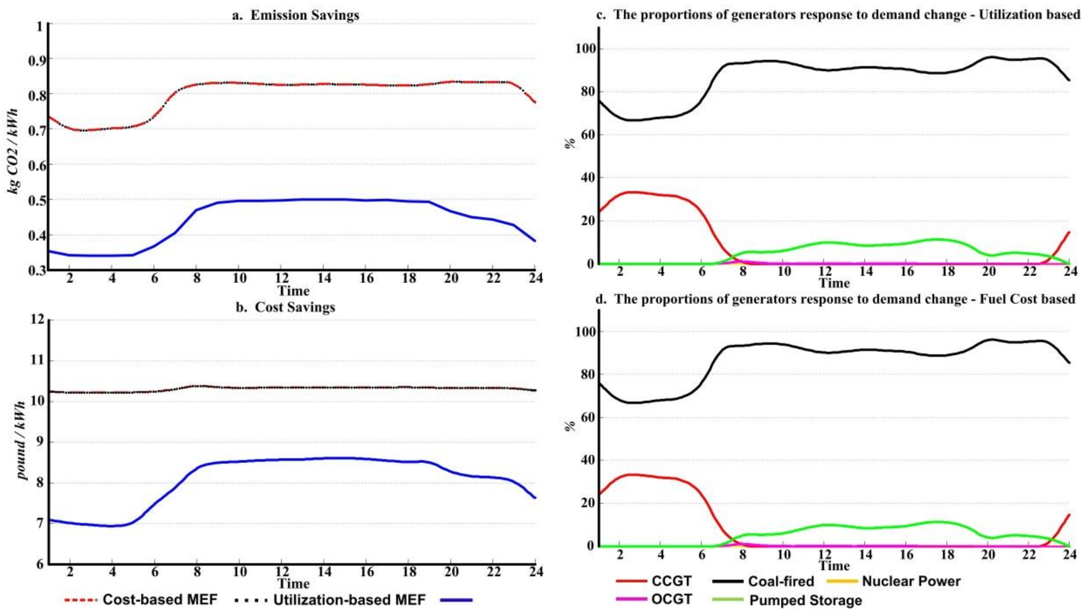

Figure 4-24 Typical summer demand, 10% demand reduction

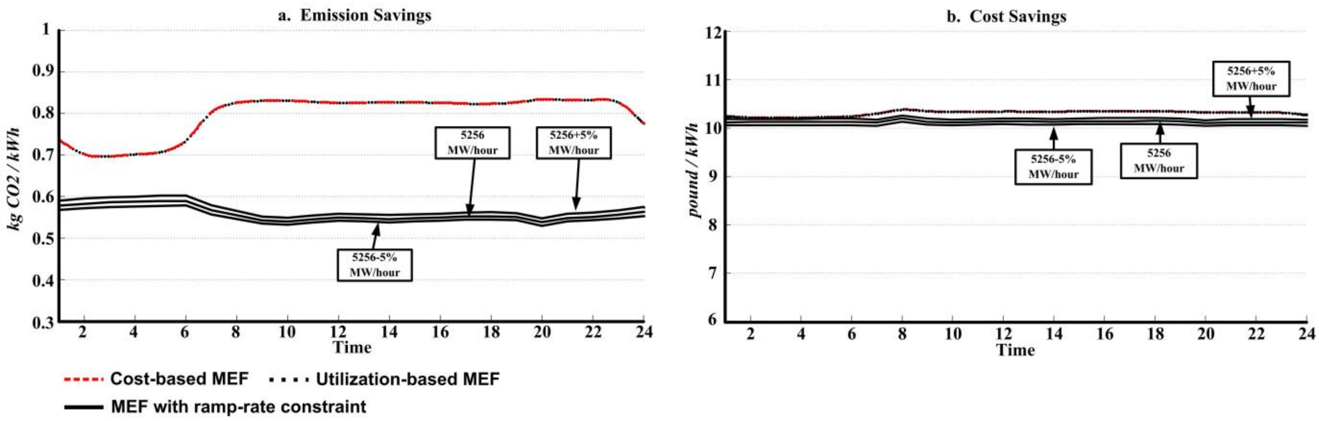

Figure 4-25 Typical summer demand, 10% reduction with ramp-rate constraint

However, if considerations of ramp-rate constraint are included in MEF estimation (shown in Figure 4-25), the coal-fired generators are constrained. Part of the demand changes have to be transferred to CCGT units, depending on how much the coal-fired power is constrained. So the MEFs turn out to be a coalition of the two technologies.

From these three level of demand reductions (1%, 5%, and 10%), it can be seen that both the utilization-based MEF and the cost-based MEF are higher than the system average emission rate in all scenarios. If constraints of ramp rate are considered in the estimation, the MEFs are lowered when demand changes are bigger enough to affect the assumed merit order. Results confirm the conclusion that when demand reduction is significant (10% in this scenario), the ramp rate can have an important impact on the MFEs' estimation and consideration of ramp-rate constraint becomes indispensible.

4.7.2 Different Fuel Prices

In order to see how MEFs might be affected with different fuel prices in summer scenario, the current prices scenario and the future prices scenario are also used in this study. Results of relevant MEFs are shown in the following.

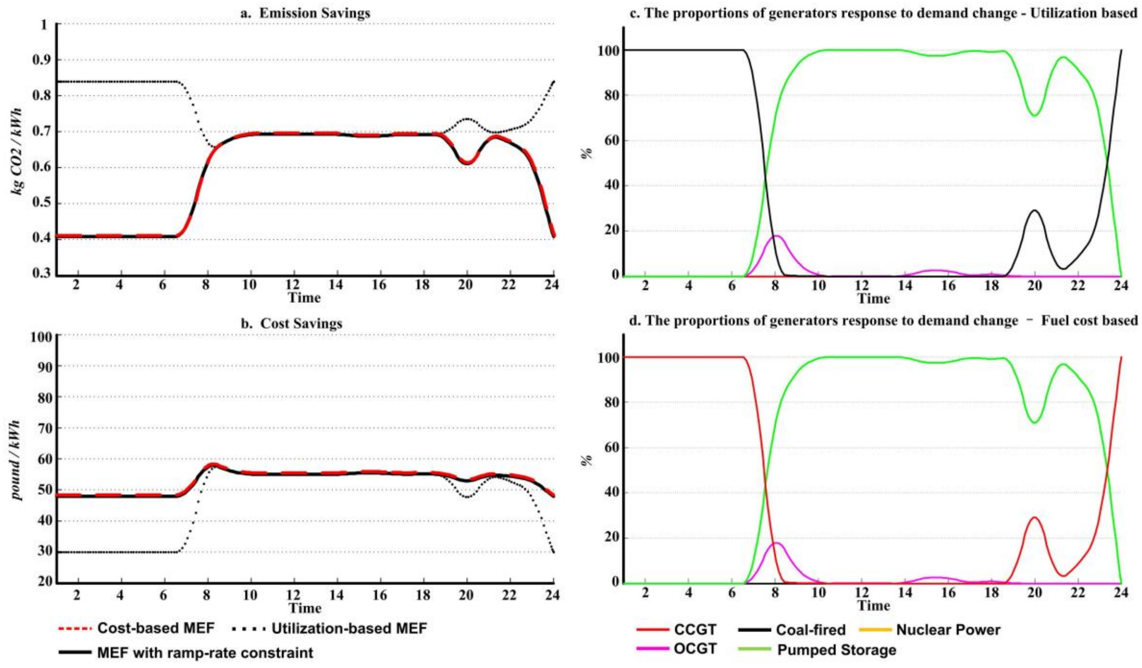

Figure 4-26 Typical summer demand, 1% reduction, current fuel prices

When the fuel prices are replaced with the current prices, the merit order reshuffles and CCGT units replacing the coal-fired become the marginal plants. Fuel-cost-based MEFs become much smaller as CCGT is a cleaner technology than coal. Such a replacement is even clearer when the demand reduction is set to be 5% and 10%.

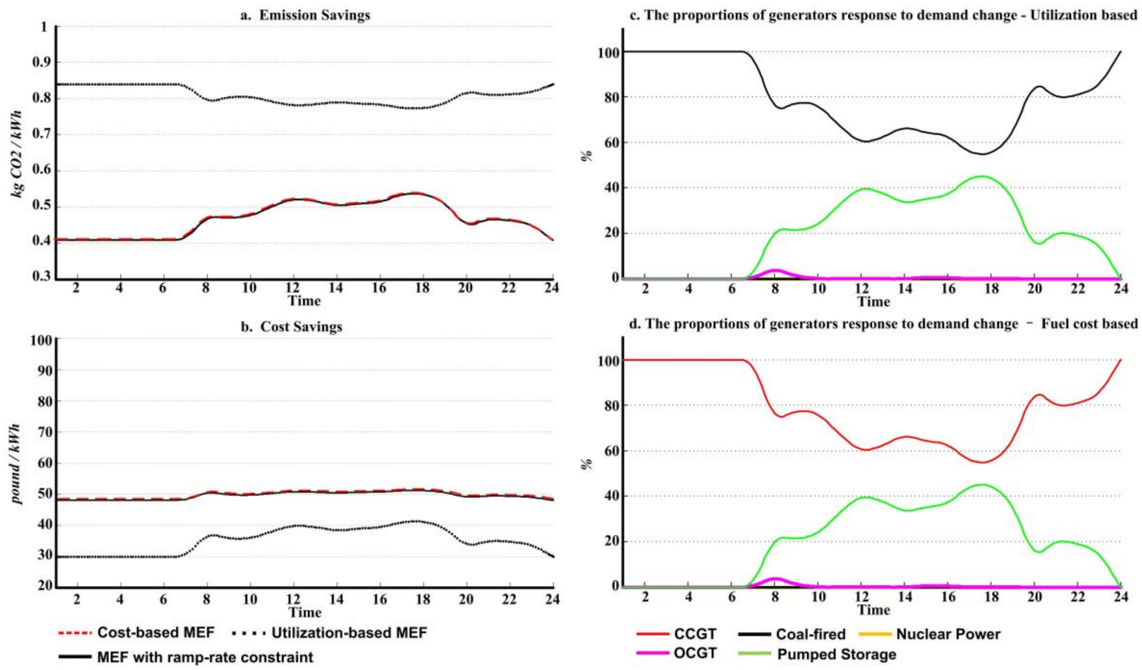

Figure 4-27 Typical summer demand, 5% reduction, current fuel prices

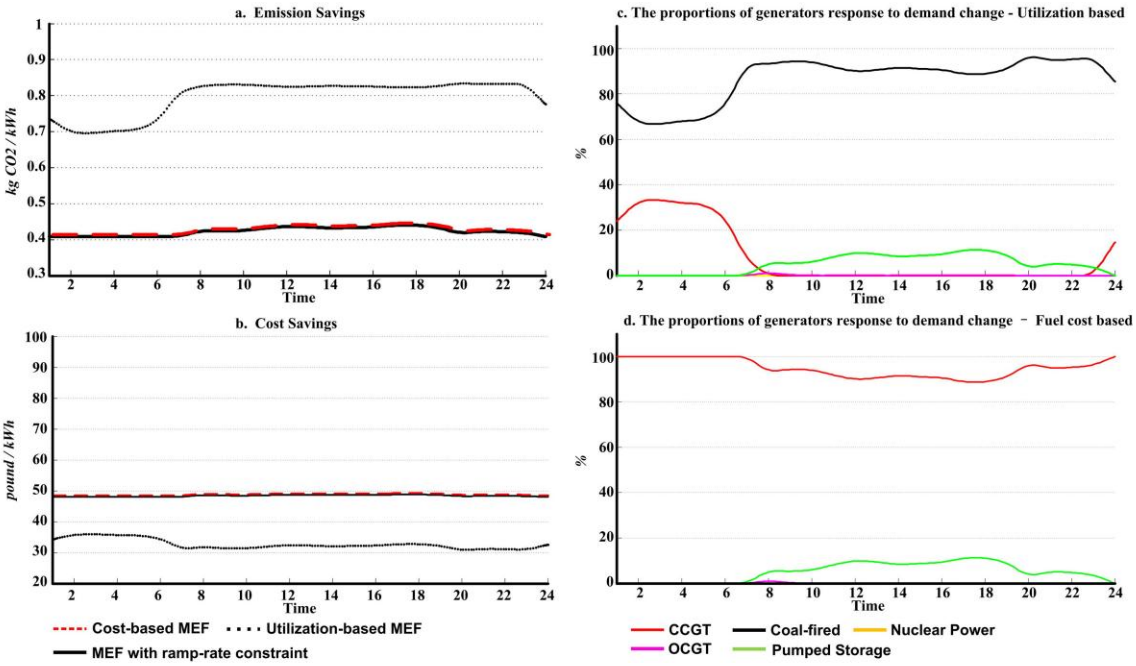

Figure 4-28 Typical summer demand, 10% reduction, current fuel prices

When the future fuel prices are used to set up the merit order, nothing is changed except the potential cost savings. Potential cost savings are expected to be higher than the current because of the increase in fuel prices, but Estimated MEFs are hardly changed and generators take response in the same way as the current prices scenario.

As mentioned previously, the fuel-cost-based MEF is determined by the fuel prices. Based on the projections of the DECC, the coal price will increase by 29.47% till 2032 and the gas price will increase by 23.33%. But, coal will be still cheaper than the gas in terms of fuel price. That is the reason why the current scenario yields the similar result as the future scenario. That is also the reason why the marginal emissions savings are not sensitive to the price changes from now on, even under a fuel cost based merit dispatch.

The analyses of summer scenario confirm the conclusion made by winter scenario, that fuel-cost-based MEFs are significantly changed between the past scenario and the current scenario, that the ramp rate can have a big impact on the MFEs' estimation especially when the demand changes are significant, and that consideration of ramp-rate constraint becomes indispensible.

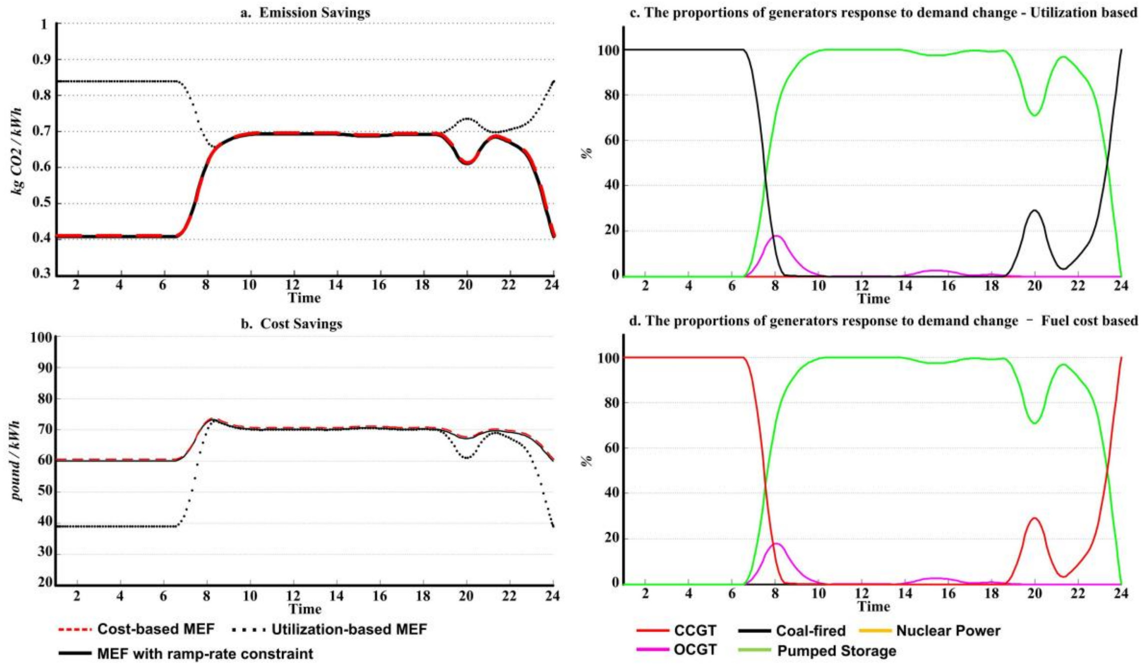

Figure 4-29 Typical summer demand, 1% reduction, future fuel prices

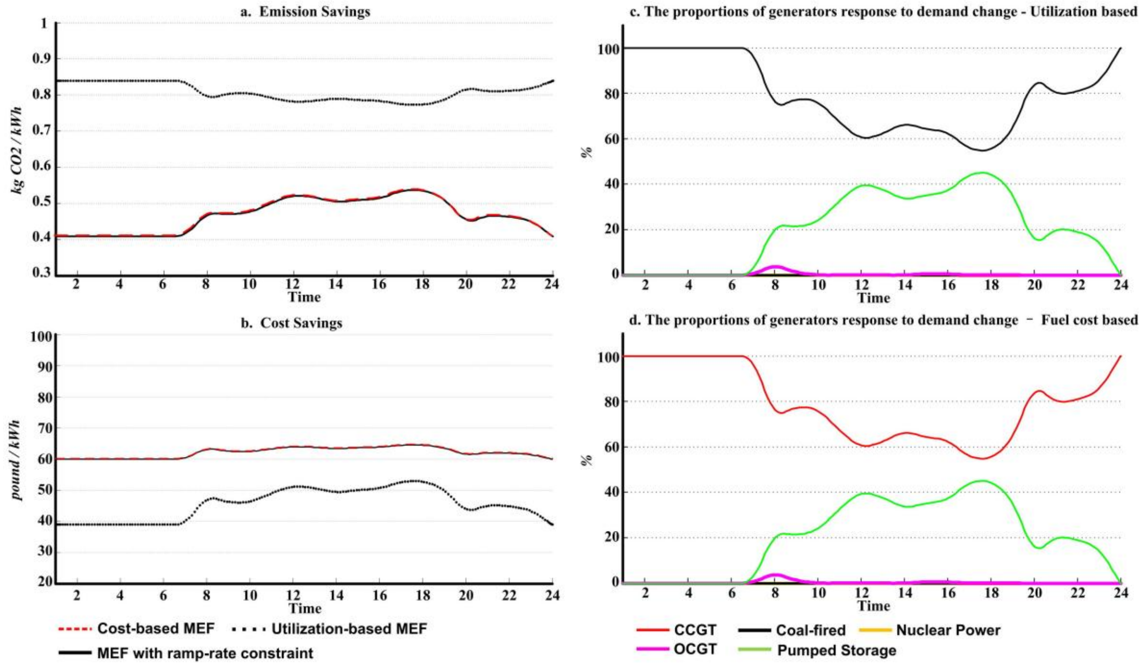

Figure 4-30 Typical summer demand, 5% reduction, future fuel prices

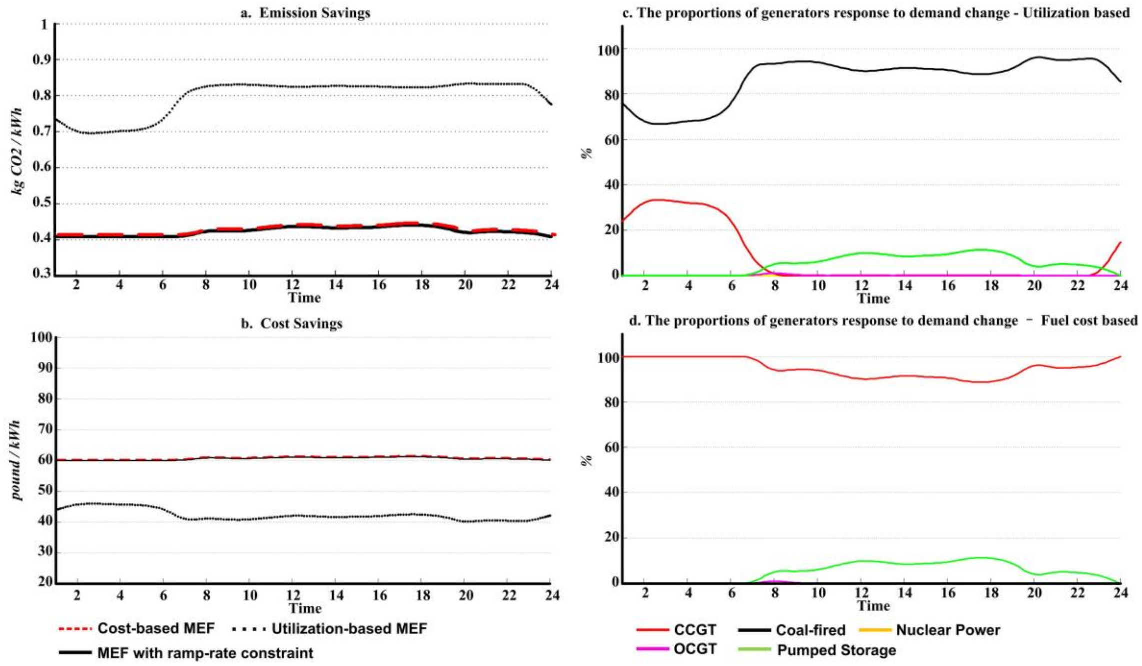

Figure 4-31 Typical summer demand, 10% reduction, future fuel prices

4.8 Chapter Summary

This chapter proposes an improved MEF estimation model by considering ramp-rate constraint in fuel-cost-based merit order dispatch. It is applied into British electricity system to illustrate the differences between AEF and MEF in GB, and comparisons with two conventional merit order approaches of estimating MEF (utilization-level-based and fuel-cost-based) are also made. Sensitivity analysis of MEFs to a few scenarios of fuel price is done at the end of this chapter to see how MEFs might change with different prices. Some conclusions can be drawn as:

- All previous studies have argued that MEF is higher than system-average rate and application of AEF into marginal impact assessment can lead to significant underestimation of emission savings. However, demonstrations in the GB electricity system showed that the MEF can be lower than the AEF when low-carbon generators working on the margin and being triggered by demand response.

- Case studies show that MEFs display a high degree of variability over the course of a year and over the course of a day. Therefore, a fixed marginal factor for both peak and off-peak times is not justified, i.e. a single marginal emission cannot provide adequate reflection of the potential carbon savings from demand response for each time period during a day.

- Case studies show that fuel-cost-based MEFs and utilization-based MEFs obtain similar estimation during the night time, but their differences in estimating MEFs during the peak time is significant, especially in the winter scenario.

- When the demand reduction is small, impact of generators' ramp rate on the estimation of MEF is trivial as the flexible generator has enough capability to balance the reduction. But if the demand reduction is bigger than the ramping ability of the coal-fired generators, such as 5% and 10% in the demonstration, the ramp-rate constraint has a big major impact and consideration of the ramp-rate constraint in the dispatch order becomes indispensible.

- The fuel-cost-based MEFs are subject to the fuel price considered. The MEFs in the past price scenario are much higher than the MEFs in the current price scenario. However, for the future price scenario, the MEFs based on fuel cost order are the same as the current price scenario because the price of gas is always much more expensive than that of coal.

- Case studies show the potential of increasing the MEF by triggering heavy carbon polluters working on the margin, which illustrates the importance of introducing carbon mechanism to the power sector. The point is that if the carbon prices introduced can make low-carbon technology become competitive in generation, the environmental benefit by Demand-side response is also enhanced.

Chapter 5

Marginal Emissions Factor with Carbon Mechanism

THIS chapter improves the MEF estimation by considering both the utilization level of generators and the carbon costs when determining the dispatch merit order.

5.1 Introduction

Power sector is the single largest source of carbon emission around the world, accounting for 25.9% of global carbon emission [32]. Decarbonization of the power sector is important for the transition to a sustainable and low-carbon world economy. Many policies, technologies and regulations have been introduced to decrease emissions of greenhouse gases in the power sector.

In the generation side, coal-fired and gas-fired power plants that are dominant in the power sector will be gradually and partly replaced by generators driven by renewable sources [16]. Instruments and policies, like carbon taxes or emission trading schemes will be introduced into the power market to control the greenhouse gas emission [22-24]. Generally, economists agree that the most effective way to combat carbon emissions is to introduce a price on it, commonly referred to a carbon price, which must be paid by the emitter [24]. The introduction of a carbon mechanism, either tax or credit in an emission trading scheme, would impact on generation costs. With carbon costs included, heavy polluters with cheap fuel (such as the coal-fired units) can become relatively more expensive than lighter polluters with expensive fuel. Some generators may change their roles in the merit order, changing from operating continuously to operating on the margin to meet the flexible demand. The merit order in which generators are ranked to dispatch is therefore altered.

In this chapter, a method of internalizing emission as a part of generation cost is proposed to assess the impact of carbon cost on the generators' profile. Taking into consideration generator's utilization level, it assumes generators are dispatched according to the summation of minimal fuel costs and carbon costs. The most expensive units are curtailed first when demand reduction emerges. The proposed MEF approach and the fuel-cost-based MEF approach are then applied in the British electricity systems in two typical loading scenarios: winter demand and typical summer demand. Effort is also made to project the MEF into the next ten years to assess the impact of demand-side response over a long time horizon.

5.2 Carbon Prices

In EU, the power sector is covered by the EU Emissions Trading System (EU ETS). The EU ETS is a 'cap and trade' system. A 'cap', or limit, is set on the total amount of certain greenhouse gases that can be emitted by the factories, power plants and other installations in the system [74-76]. Within the cap, companies receive or buy emission allowances which they can trade with one another as needed [74].

The introduction of this carbon mechanism can have a significant impact on generation costs. Most of generators in power sector are carbon emitters. They might need to pay a significant amount of allowance fee to the carbon trading market to generate electricity. What is worse, if a company (in power sector generators mainly) does not have enough allowances to cover its own carbon emissions for each year, it will get fined heavily.

Launched in 2005, the EU ETS is a market-based carbon mechanism. It is now in its third phase which will run from 2013 to 2020. The main changes of phase 3 can be summarized as [74]:

- A single EU-wide cap on emissions taking place of the previous system of national caps;
- Auctioning, not free allocation is now the default method for allocating allowances. In 2013 more than 40% of allowances will be auctioned, and this share will rise progressively each year;
- For those allowances still given away for free, harmonized allocation rules apply which are based on ambitious EU-wide benchmarks of emissions performance;
- Some more sectors and gases are included.

Figure 5-1 EU ETS carbon prices from 2006 to 2013 [77]

As can be seen in Figure 5-1, carbon prices in the trading market have been low since 2009, staying around €5 per allowance. Low carbon prices cannot give enough incentive to promote low-carbon technology. In order to provide the robust and reliable incentive that the ETS is so-far failing to deliver, the UK has decided to introduce a unilateral “carbon floor price” [78-79]. The carbon floor price is a “top-up fee” paid by the UK carbon polluters if the market price is below government’s targeted level, announced in the treasury’s budget statement. According to an official document called Carbon Price Floor in the House of Common’s library, the target price trajectory is to be around £30/tonne CO_2e in 2020 and £70/tonne CO_2e in 2030.

By putting a price on carbon and giving a financial value to each tonne of carbon emissions, a heavy polluter with cheap fuel (such as the coal-fired units) might become far more expensive than it used to be, possibly more expensive than a light polluter with expensive fuel, depending on how much the carbon price is.

On the other hand, if carbon emissions are charged and generators are obligated to pay carbon prices to the trading market along with the top-up fee paid to the treasury, the cost of generating electricity inevitably changes and the merit order used to get MEFs needs to be reassessed. The merit order, if cost-based, reshuffles in the MEF assessment, dependent on the carbon price targeted. In this chapter, based on the trajectory of governmental carbon prices, sensitivity analysis using various carbon prices is carried out in the following sections.

5.3 Model Description

The conventional merit order based MEF approach assumes the most expensive generators (fuel costs) are on the margin for a given system loading level and then calculates the marginal change in CO_2 emissions as a result of demand change. However, the fuel cost of each generation technologies is assumed to be fixed, and the utilization level of generators is thus not factored into the fuel cost. Further driver to a new MEF approach is the introduction of carbon price, where the most expensive generator can no longer be solely decided by the fuel cost. For example, the coal-fired units are cheap in fuel but very expensive in carbon emissions, thus they need to be curtailed first when demand reduction takes effect. Therefore, in a low carbon energy system, both the utilization level of generators and the carbon costs must be considered in MEF assessment, and a new merit order based approach is needed to improve the traditional MEF estimation.

5.3.1 Evaluating the Effect of Utilization Level

This section develops methodology to evaluate fuel cost against each generation technologies when they are at levels of outputs, i.e. differing degree of plant utilization.

Theoretically, power plants operating with low output are less efficient compared with their full-load design efficiency [80-81]. One index to measure the efficiency of power plants is heat rate, which calculates the amount of heat input in British thermal units per hour for each kilowatt-hour of electricity produced [82]. It takes into account all the energy a plant consumes to operate the generator(s) and other equipment, such as fuel feeding systems, boiler water pumps, cooling equipment, and pollution control devices [80]. For example, a heat rate of 1000 Btu/kWh represents a generating unit requiring 1000 Btu of heat to generate one kWh of electricity. A unit that has a heat rate of 800 Btu/kWh is more efficient than a unit with a heat rate of 1000 Btu/kWh. Generally, the heat rate of a fossil-fuel plant can be defined by the equation [83]:

$$HR = ax^2 + bx + c + \frac{d}{x} \tag{5-1}$$

Where, x refers to the loading level of a generator. a, b, c, d are the coefficients that define the equation.

To evaluate the effect of utilization level of generators for a whole country, the general principle is to model each generator independently, but complexity can be reduced by modelling each generation technology as a group. For example, generators in England and Wales were categorized into ten groups according to different technologies in Reference [37] to assess the MEF. This paper represents each generation technology as a group of generators and assesses the effects of utilization level on each technology.

Commonly, the available data of the electric system is the energy mix and dispatch data of each technology including generation efficiency and capacity factor for a period of time. Therefore, based on the dispatch data of generation efficiency and capacity factor, this paper finds a proxy for estimating effect of utilization level on each technology. Optimal coefficients (a, b, c, d) of each technology are determined by using Generalized Least Square (GLS) [84-85]. One set of the coefficients is applied to a heat-rate equation (Eq. 5-1) to represent the performance of each generation technology at differing operating points.

With the optimal coefficients for heat-rate equation, the fuel costs of power plants can be obtained as:

$$FC_{coal} = HR_{coal} \times F_{coal} \tag{5-2}$$

$$FC_{gas} = HR_{gas} \times F_{gas} \tag{5-3}$$

Where, FC_{coal} and FC_{gas} refer to the fuel costs of coal-fired and gas-fired units; HR_{coal} and HR_{gas} are the heat rates; F_{coal} and F_{gas} are fuel costs of thermal power, indicating how much fuel cost is needed to produce 1 Btu of energy (pence/Btu), 6.8220×10^{-4} pence/Btu for the gas-fired unit and 3.189×10^{-4} pence/Btu for coal-fired unit [86].

5.3.2 Internalizing Carbon Cost as a Part of Generation Cost

To evaluate how much the generation costs might change due to the consideration of carbon costs, it is required to assess how much carbon emission is produced when generating electricity. Carbon dioxide is released by the combustion of fuels that contain carbon. The emissions directly depend on the amount of carbon in the fuel and the quantity of fuel burnt. To evaluate the carbon emission, heat rate is multiplied by the amount of carbon emission emitted when generating thermal energy. The carbon emission can be obtained as:

$$Emission_{coal} = HR_{coal} \times EF_{coal} \tag{5-4}$$

$$Emission_{gas} = HR_{gas} \times EF_{gas} \tag{5-5}$$

Where, $Emission_{coal}$ and $Emission_{gas}$ refer to the carbon emission of coal-fired and gas-fired unit; HR_{coal} and HR_{gas} are the heat rates; EF_{coal} and EF_{gas} are emission factors indicating how much carbon emission is emitted when generating 1 Btu thermal energy, 1.2666×10^{-4} kg CO_2 per Btu for the gas-fired and 0.4253×10^{-4} kg CO_2 per Btu for coal-fired unit [45].

The level of the carbon price and its uncertainty is one of a number of factors affecting merit order, according to which generators are dispatched. The projection of carbon price is outside the scope of this paper. In this paper, the values set by DECC are used to quantify the carbon costs of generation. Then the carbon cost equation can be obtained as:

$$CC_{coal} = HR_{coal} \times EF_{coal} \times CP \tag{5-6}$$

$$CC_{gas} = HR_{gas} \times EF_{gas} \times CP \tag{5-7}$$

Where, CC_{coal} and CC_{gas} refer to the carbon cost of coal-fired and the gas-fired unit; CP refersll to the carbon price.

Therefore, the generation cost internalizing carbon emissions costs can be expressed as:

$$\begin{aligned} FCC_{coal} &= FC_{coal} + CC_{coal} \\ &= HR_{coal} \times F_{coal} + HR_{coal} \times EF_{coal} \times CP \\ &= HR_{coal} \times \left(F_{coal} + EF_{coal} \times CP \right) \end{aligned} \tag{5-8}$$

$$\begin{aligned} FCC_{gas} &= FC_{gas} + CC_{gas} \\ &= HR_{gas} \times F_{gas} + HR_{gas} \times EF_{gas} \times CP \\ &= HR_{gas} \times \left(F_{gas} + EF_{gas} \times CP \right) \end{aligned} \tag{5-9}$$

Where, FCC_{coal} and FCC_{gas} refer to the sum of fuel cost and carbon cost of coal-fired and gas-fired unit.

5.3.3 A New Merit Order Approach of Assessing MEF

To grasp the of demand side on carbon emission, start-up criteria is needed to determine which plants have the priority to meet the demand change in a power system. Based on the assumption that generators with highest costs (fuel costs plus carbon costs) should be responsible for emerging demand reduction first, the generating plants are ranked according to the following equation to dispatch:

$$Rank = \min \left\{ FCC_1, FCC_2, \cdots, FCC_i, \cdots, FCC_N \right\} \tag{5-10}$$

Where,

$$\begin{aligned} FCC_i &= FC_i + CC_i \\ &= \left(ax_i^2 + bx_i + c + \frac{d}{x_i} \right) \times \left(F_i + EF_i \times CP \right) \end{aligned} \tag{5-11}$$

where, FCC_i refers to fuel cost plus carbon cost of generator i, defined as Fuel Carbon Cost (FCC) , FC_i refers to fuel cost, CC_i refers to carbon cost, x_i refers to loading level of generator i.

For each settlement period, the FCCs of generators are determined by both the generators' utilization level and the relevant carbon cost. Generators in the system are then rearranged according to the results from Equation 5-11. The generator with the most expensive FCC is the first priority to respond to emerging demand reduction firstly, while cheaper units are kept on operating in the system.

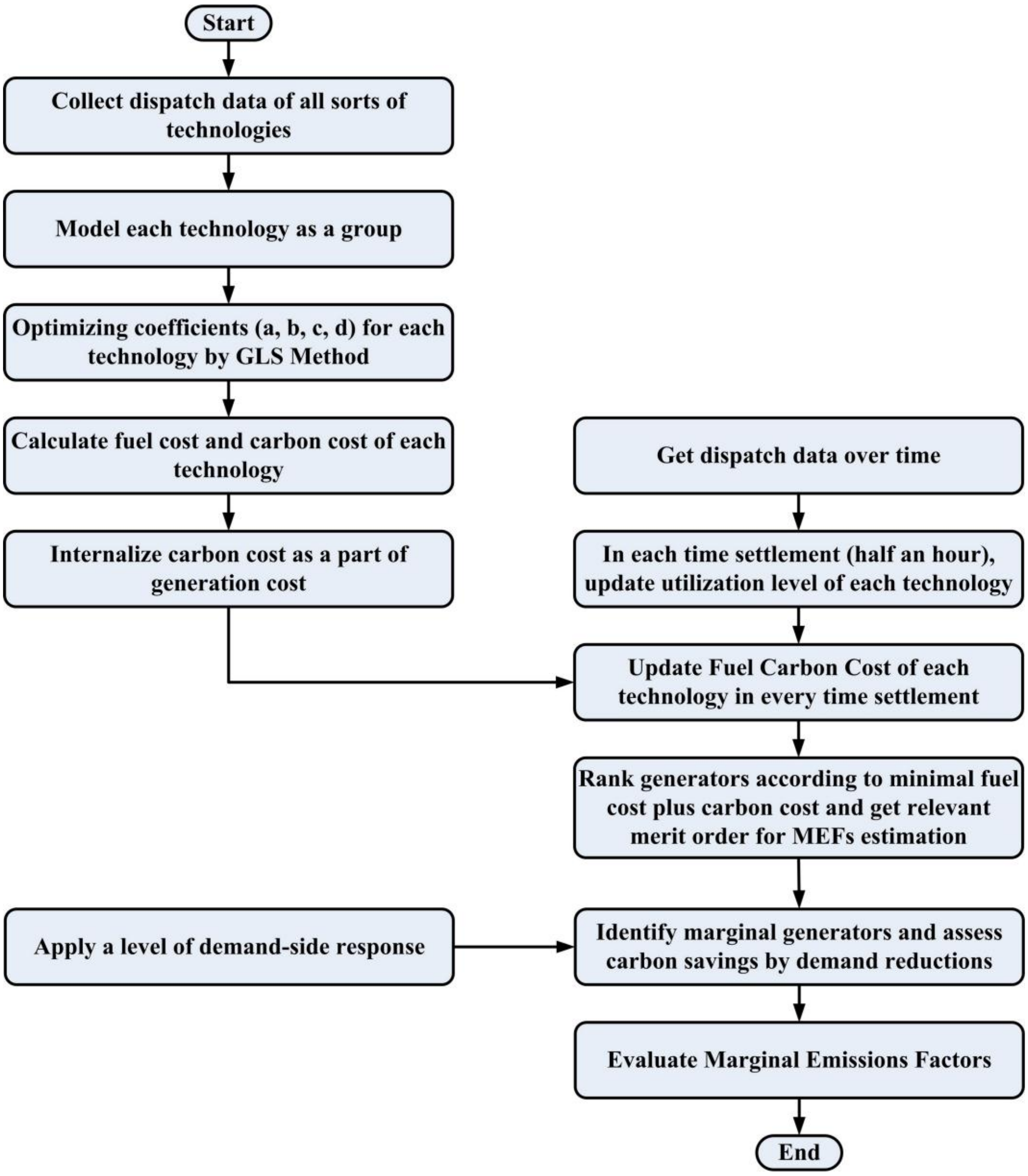

Figure 5-2 Flow chart of the new merit order approach

5.4 Case Study I: Evaluating Carbon Mechanism

A British electricity system is used in this chapter to validate the proposed method. Dispatch data of generation efficiency and capacity factor in Great Britain are used to analysis the impacts of carbon price on the generators' profile.

5.4.1 A Proxy for Estimating the Efficiency of Generators

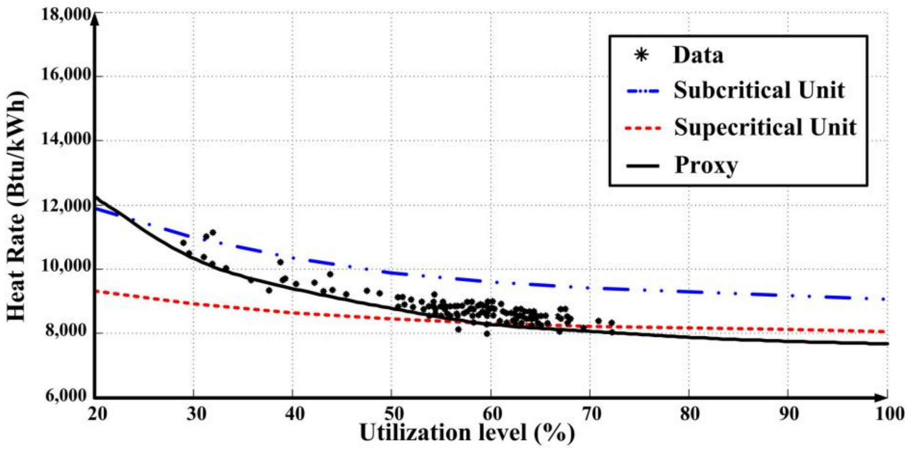

Figure 5-3 A proxy for heat-rate performance of coal-fired unit in Great Britain

By the method proposed in part A of Section II, a proxy for estimation of heat-rate performance of coal-fired plants in the GB can be obtained in Figure 5-3. To confirm the validity of this proxy, two typical heat-rate curves of subcritical and supercritical coal generating units are used to make comparisons with the proxy [87]. It can be seen that, although there is more variability of generators' performance in practice, the impact of operating load on the coal-fired units are well represented by the obtained proxy. This estimation shows that, the most coal-fired units consume 9000 to 11000 Btu to produce 1 kWh of electricity. However, when operating at low output such as 20% loading condition, around 14000 Btu is needed to generate the same amount of electricity.

5.4.2 Fuel Cost and Carbon Cost with Different Utilization Level

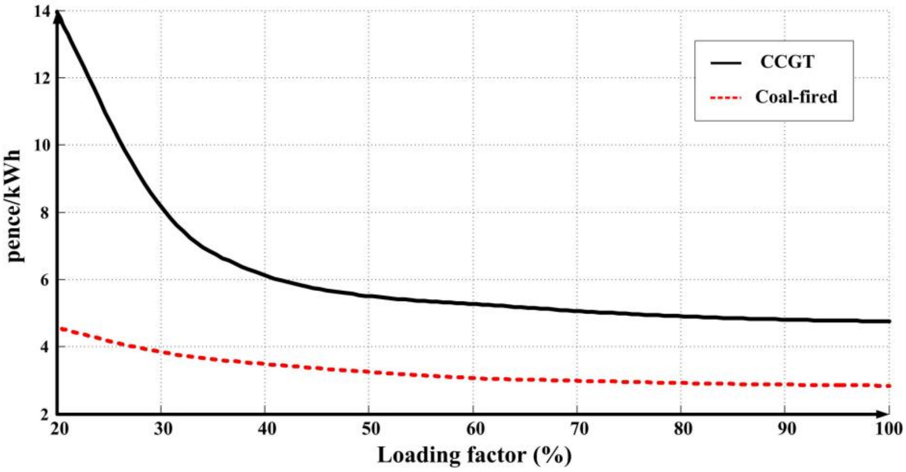

Figure 5-4 Fuel costs of CCGT and coal-fired plant

With the fitting cure, the sensitivities of fuel costs to the loading level can be obtained by Equation (5-2) and Equation (5-3). It is clear in Figure 5-4 that both technologies generate electricity at lower fuel costs when operating closer to their designed ratings. Without introducing carbon costs, the coal-fired plants are more competitive than Combined Cycle Gas Turbine (CCGT) and ought to keep working in the system for more hours. The fuel-cost-based merit order is therefore reasonable, as it assumes the CCGT units to take demand response.

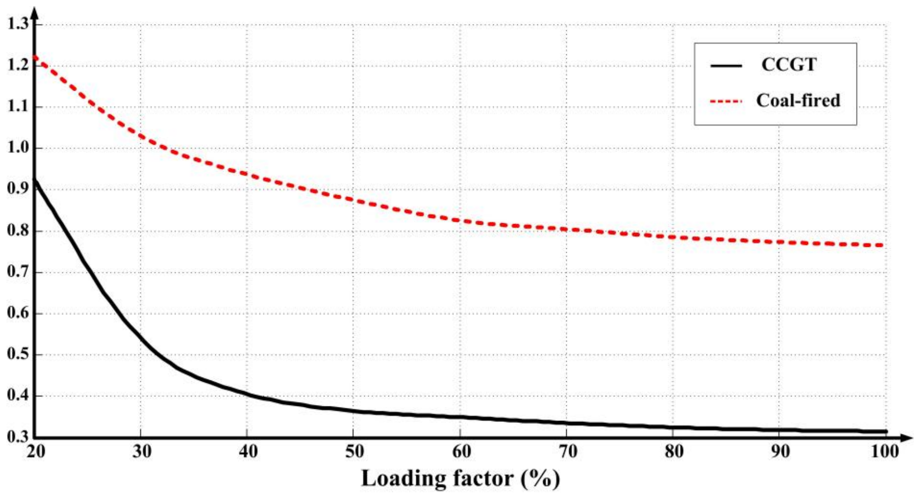

Figure 5-5 Carbon costs of CCGT and coal-fired plant

By Equation 5-6 and Equation 5-7, the sensitivities of carbon costs to system loading level are shown in Figure 5-5. Based on the carbon prices in 2013 that was around £4 market price plus £5 top-up fee paid to treasury, it can be seen that coal-fired plants need to pay much higher carbon costs than CCGTs because they are heavier carbon emitter. If carbon price support mechanism is introduced, its impact on coal-fired plants is much bigger than that on CCGT units. However, the carbon cost is very insignificant compared with the fuel cost under current carbon price scenario. Heavy polluters might not pay enough attention to the consequences of carbon emissions. The carbon price, although still over low currently, is projected to go up in the following decades, targeted to be around £30/tonne CO_2e in 2020 and £70/tonne CO_2e in 2030. The question is how much the price of pollution is high enough to encourage generation from low-carbon technology and thus reshuffle the merit order. The following section is to set up such sensitivity analysis using various carbon prices.

5.4.3 Impact of Carbon Price

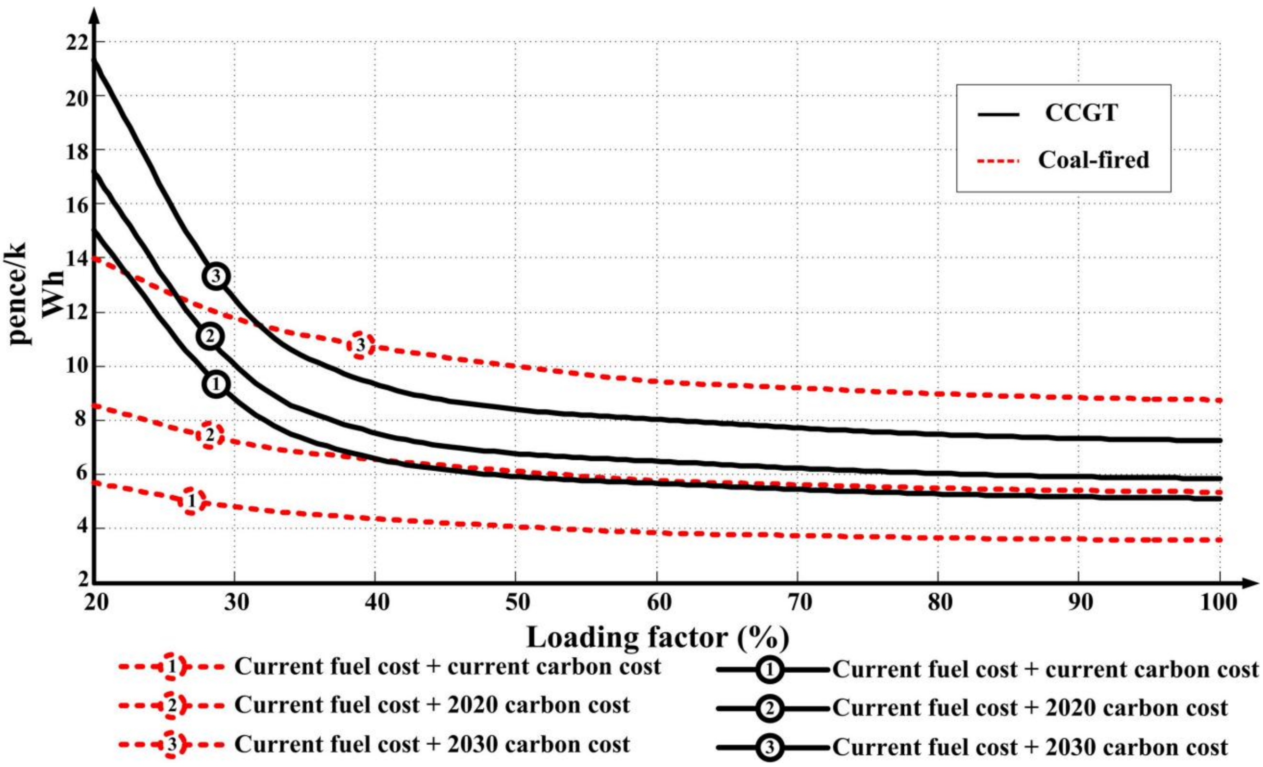

Figure 5-6 Internalizing fuel cost and carbon cost for CCGT and coal-fired plant

Generally, cheaper generation units in an electricity system operate for more hours, and those relatively more expensive units operate for fewer hours. The coal-fired units therefore ought to operate more often than CCGTs as they are cheaper in fuel costs.

It can be seen from Figure 5-6 that with a carbon mechanism the cost of coal-fired units increases significantly with an increase in carbon costs. Thereby, when the carbon price is set to be the 2030 value of £70/tonne CO_2e, CCGT units will become a more reasonable choice of supplying electricity compared with the coal-fired. Their FCCs (fuel cost plus carbon cost) are lower and carbon emissions are fewer. That means the coal-fired units ought to be curtailed first when demand response takes effect, which is different from the assumption made by the fuel-cost-based merit order that assumes the CCGT units to be curtailed first.

However, when the units operate with a low output (less than 38% in Figure 5-6), the coal-fired plants are still cheaper than CCGT units. The CCGT units ought to be curtailed first, which is the same as the assumption made by the fuel-cost-based merit order.

Therefore, a fuel-cost-based merit order is not efficient for evaluating environmental benefits of demand response when introducing a sufficient carbon mechanism. A new merit order approach of assessing MEF with the consideration both loading level of the units and carbon cost, is therefore necessary.

5.5 Case Study II: Estimating MEFs in the GB

To set the comparisons of MEFs between the proposed merit order and the fuel-cost-based merit order in an appropriate context, typical winter demand and typical summer demand in GB electricity system are used in this study. The British electricity system largely consists of three major groups of power plants: nuclear power plants (13%), Combined Cycle Gas Turbine (CCGT) plants (35%), and coal-fired units (35%).

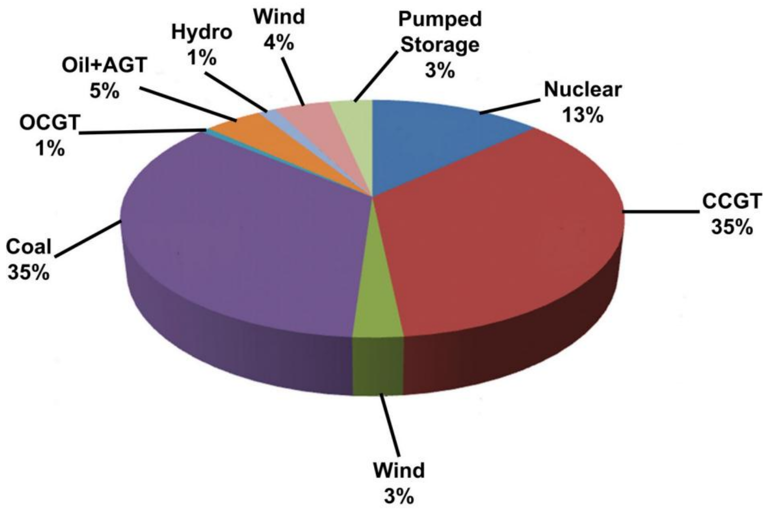

Figure 5-7 GB’s Generation mix in 2010

Electric power planners expect increased participation in demand response to decrease peak electric power demand by up to 5% over the next ten years. The relationship between electricity demand reduction and carbon emission is considered to be central to low-carbon emission policy. It is clear that carbon savings per kWh are not the same with various demand reductions, as different reduction can trigger different selections of generators to take response. So the sensitivity of MEF to different level of demand reduction needs to be examined. In this study, MEFs are assessed according to three reduction levels, 1%, 5% and 10%.

When the carbon mechanism is insufficient and price of carbon is too low, encouragement of using low-carbon technology is not enough to reshuffle the merit order. Estimating MEFs without considering impacts of carbon prices is not a problem as the merit order is driven mainly by the fuel price. However, if the carbon price is high, this is not the case. Based on last section’s analysis, the targeted carbon price of 2030 (£70/tonne CO_2e) is enough to reshuffle the generation cost, which is to be used in this section to see how the MEFs can be changed when a sufficient carbon mechanism is introduced.

5.5.1 Typical Winter Demand Scenario

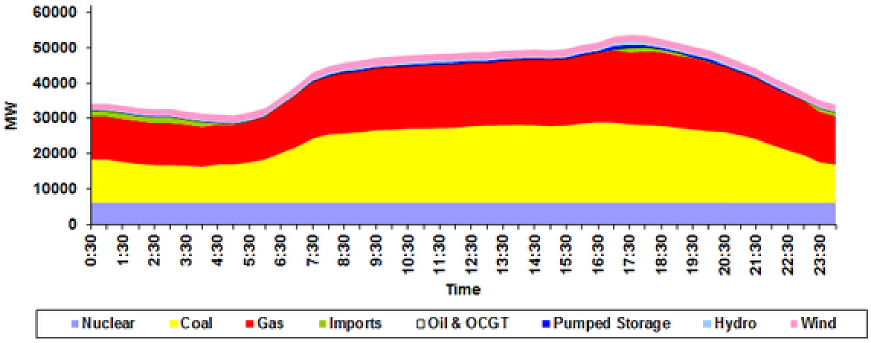

Figure 5-8 Typical Winter Demand: 17 Nov 2010

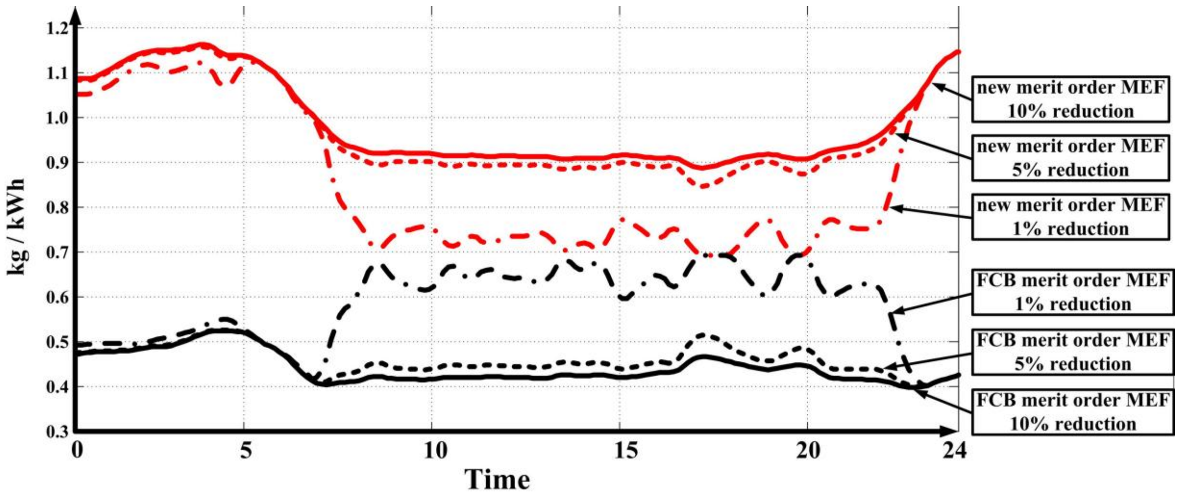

Figure 5-9 Comparison between the new MEF and fuel-cost-based MEF

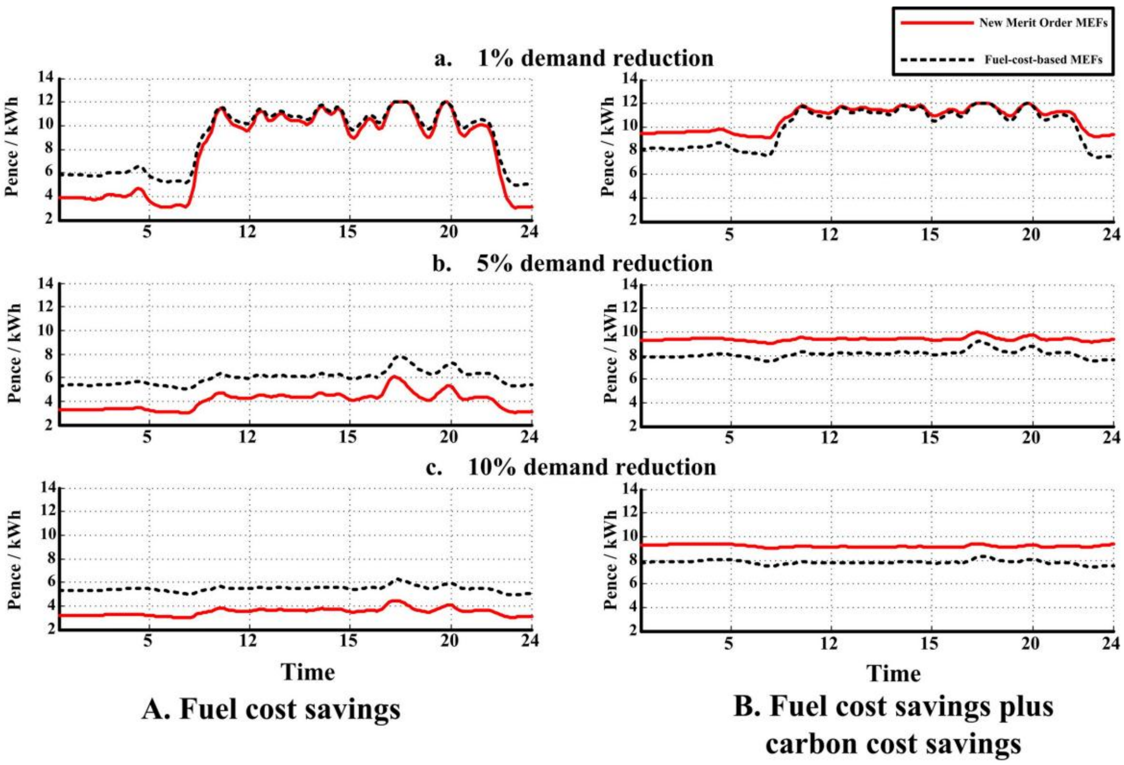

Figure 5-10 Comparison of cost savings

Figure 5-8 shows how demand was actually met in a typical winter day. The results in figure 5-9 show that there are significant differences between the proposed MEFs and the fuel-cost-based MEFs. Results of the new criteria are generally higher than the fuel-cost-based MEF (up to three times higher). This is due to generators with higher emission (like coal-fired plants) assumed to take the demand changes according to the new merit order. Fuel-cost-based merit order assumes CCGT units to response, as the fuel costs of CCGT units are more expensive. Hence, the differences between the proposed approach and the fuel-cost-based approach in assuming the prior generators to take response result in different results of assessment.

However, heavy polluters ought to be curtailed first in carbon limiting market, which is also one target of introducing a carbon mechanism. The proposed method assumes the heavy polluters (coal-fired plant) to response to an emerging demand reduction, which is plausible. But the fuel-cost-based merit order, without considering the carbon price, assumes light polluters (CCGT units) to response to demand reduction, which is questionable in future electricity system. The use of a fuel-cost-based merit order for demand-side assessment is more likely to inadequate to represent the carbon savings from a demand response.

On the other hand, the result in Figure 5-10 is a comparison of cost savings between the two methods, which indicates the fuel costs and FCCs that can be saved by different demand responses. It is clear that when a 1% demand reduction is applied, both the fuel costs and FCCs are much higher from 7am to 9pm than the rest time of the day. This is due to the start-up of pump units whose cost is considered to be higher than the coal-fired and CCGT. However, with 5% and 10% demand reductions, the MEFs become more stable throughout the day. This is because further reductions of demand are dominantly balanced by one single generation technology, either the coal-fired plants in the new-merit-order assumption or the CCGT units in the fuel-cost-based assumption.

Moreover, it can be seen from Figure 5-9 that the new MEFs tumble during day time and be lifted up by further demand reduction. Therefore, if a demand reduction scheme is to be applied during the day time (like 1% in this scenario), its carbon saving benefits are to be lower than that in the night, but its costs savings (both fuel cost and FCC) can be higher. Further demand reductions can lead to higher marginal savings of carbon emissions, but the marginal cost savings are decreased.

5.5.2 Typical Summer Demand Scenario

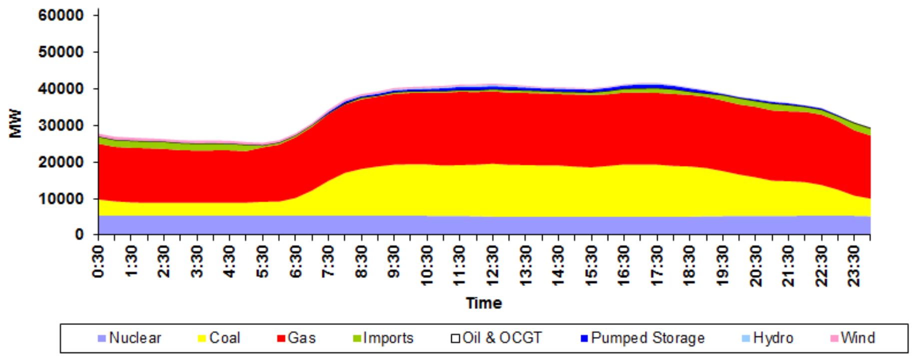

Figure 5-11 Typical Summer Demand: 10 Jun 2010

Figure 5-11 is given to show how demand was actually met in the typical summer demand. The electricity demand in GB is much lower in summer time than that in the winter time. The peak demand in typical summer day is 41631MW, compared to 53570MW in typical winter day. The capacity factors of most generators are also decreased in summer time, from 73.75% at winter peak time to 46.04% at summer peak time for coal-fired units, from 70.55% to 66.42% for the CCGTs.

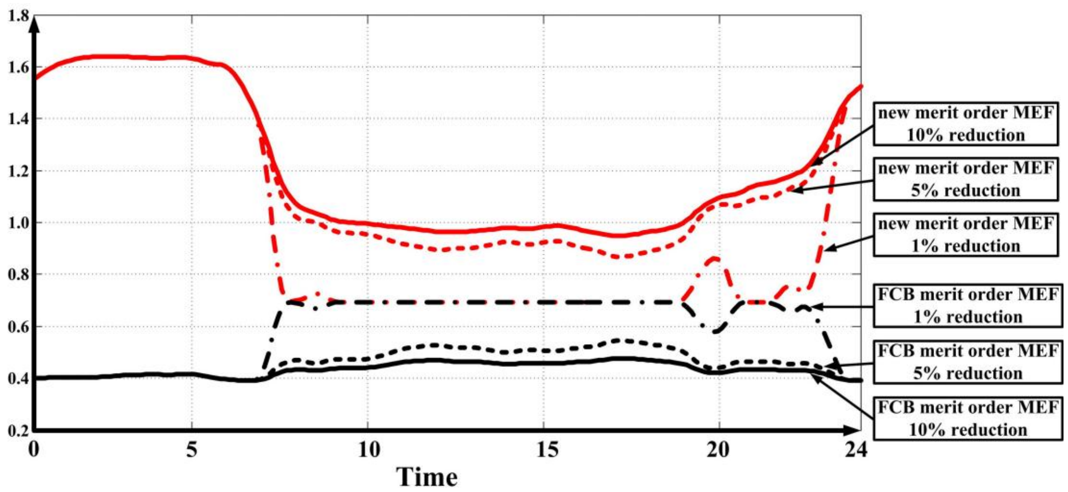

Figure 5-12 Comparison between the new MEF and fuel-cost-based MEF

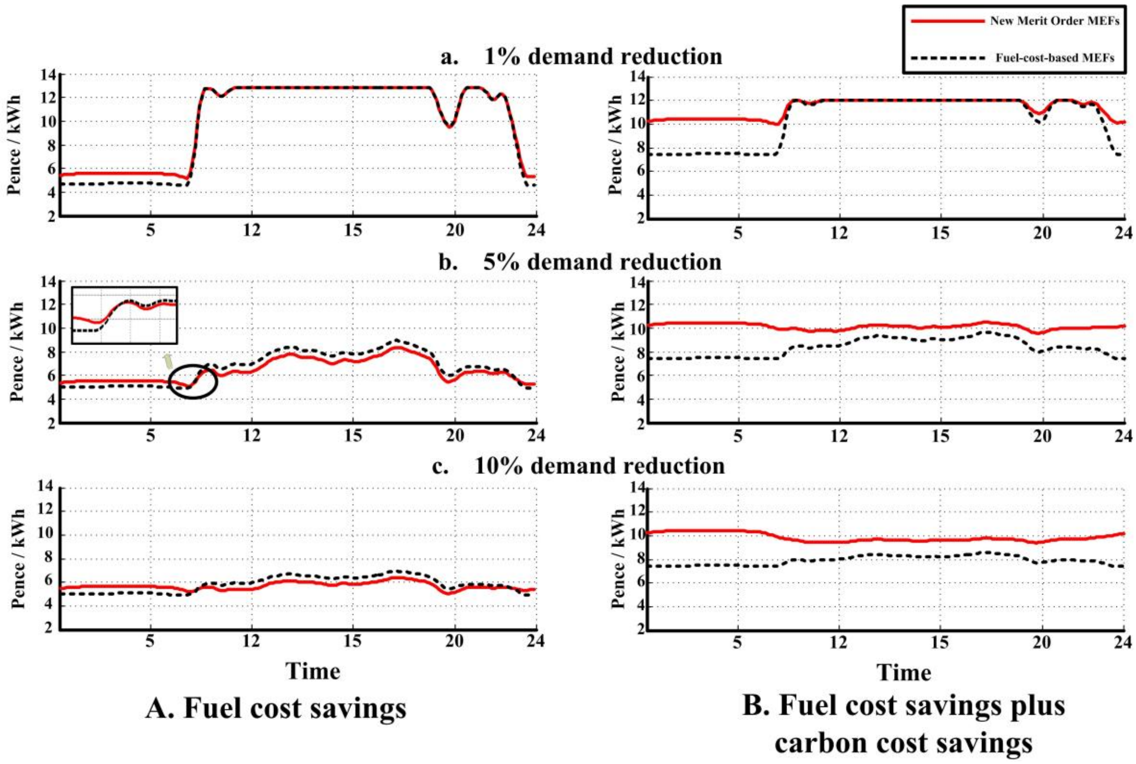

Figure 5-13 Comparison of cost savings

The proposed method assesses the summer's MEFs to be generally higher than winter's MEFs, around 1.6 kg/kWh from 1am to 7am in the summer compared to 1.1 kg/kWh at the same time in the winter. With 5% demand reduction, the MEFs are around 1.0 kg/kWh in the day time of summer, compared to 0.9 kg/kWh in winter. This increase in MEFs' assessment is because generators assumed to take the demand changes work with a lower utilization level in the summer than they do in the winter. In other words, MEFs increase with a decrease in capacity factor, even the same type of generation technology is assumed to take response.

On the other hand, during the night time, the estimations of fuel cost savings are higher by the new merit order than those by the fuel-cost-based method (See in Figure 5-13). However, it is the opposite during the day time; fuel cost savings by the new merit order method being lower than those by fuel-cost-based method.

The reason for this is the changes of generators' utilization level. Basically, the new merit order method assumes coal-fired units to be the priority to take response in both day time and night time, while the fuel-cost based method takes CCGT units. Presumably, the fuel cost savings by the coal-fired are less than those by CCGT units, as coal is a cheaper fuel. However, if we take generators' utilization level into account, the coal-fired working at low output can be more expensive than the CCGT working at high output. The capacity factors of coal-fired units vary with time in summer, from less than 20% at night to more than 45% during the day time. The capacity factors of CCGT units are generally more than 50% throughout the day. That is the reason for the opposite in fuel cost savings estimation, and that is one of the reasons why the utilization level of generators should be considered in the MEF assessment. Otherwise, the marginal savings, both carbon emissions savings and cost savings, are to be underestimated.

5.5.3 Forecasting Future into Future

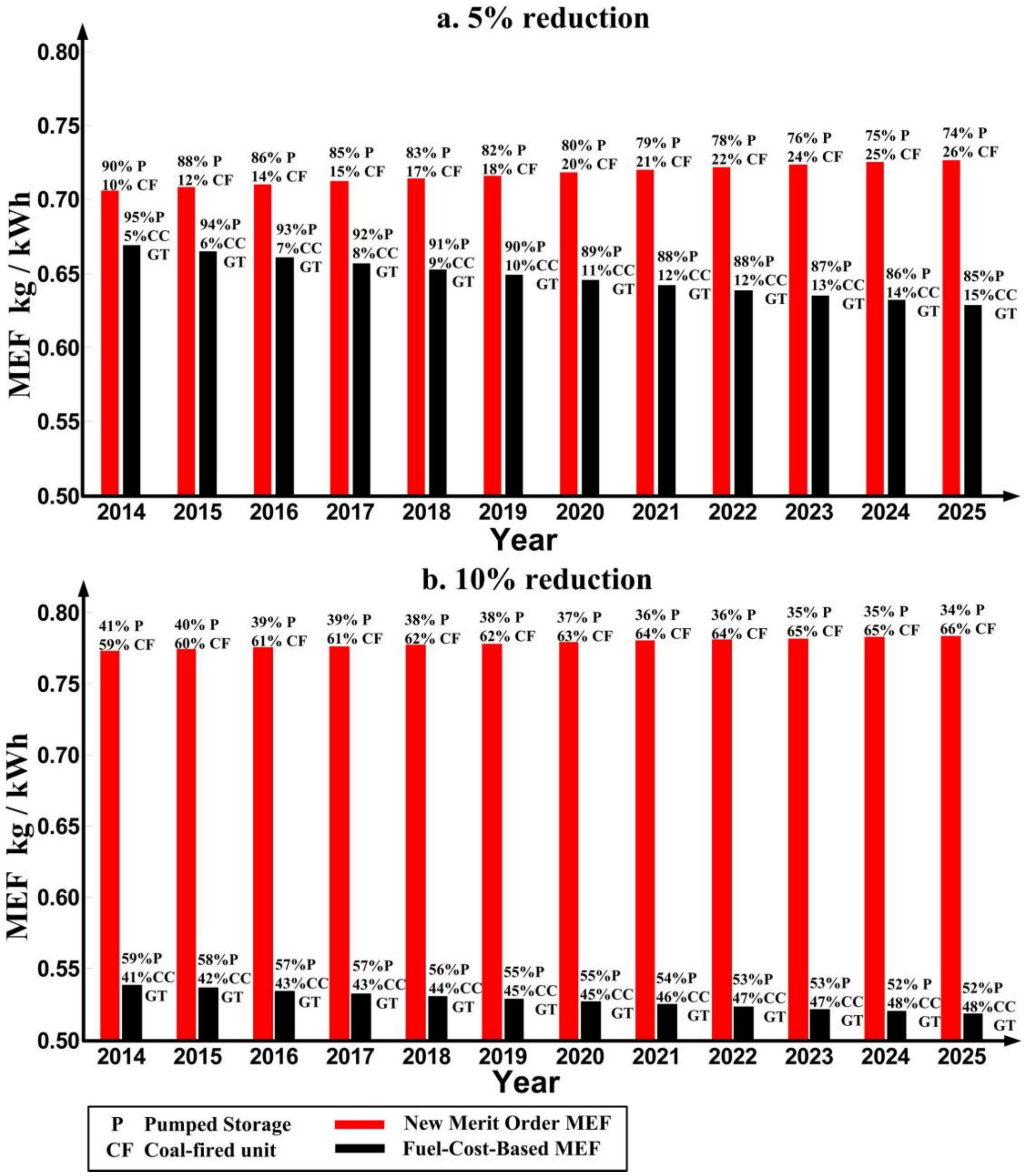

Figure 5-14 Estimated MEF for the GB system from 2014 to 2025

Estimation of Marginal Emissions Factor over a long time horizon is imperative, as environmental scheme is generally a long-term plan. The data used in this scenario is drawn from three primary sources; the cost of generating electricity by Department of Energy & Climate Change [86], the changes in generation mix and peak demand from 2014 to 2025 by the GB System Operator [88-89], and the carbon price projection by the UK Treasury [78].

The results in figure 5-14 show projected MEFs for the next decade. It is clear that different assumptions of merit order lead to opposite conclusions in MEF estimation: the proposed method estimates the MEFs to increase, but the fuel-cost-based assesses the MEFs to decrease over the next decade. The increase of the proposed method is due to coal-fired units with high carbon emissions being assumed to take more demand responses, while the decrease is due to CCGT units with light carbon emissions being assumed to response more.

However, to reduce carbon emissions, the coal-fired plants, which are heavy carbon polluters, seem to be an undesirable choice in the electricity system and will more likely to work for fewer hours in the future. They ought to be curtailed first when electricity demand is to be reduced. So estimations of new merit order MEF seem to be a more plausible estimation than the fuel-cost-based method.

5.6 Chapter Summary

In this Chapter, the impact of carbon costs on generators is investigated and its impact on the operating profiles of generators is tested in British electricity system. The Marginal Emission Factors are then assessed according to a proposed merit order approach which takes into consideration both the utilization level of generators and the relevant carbon costs. Several conclusions can be drawn from the demonstrations:

- With a carbon mechanism, the costs of coal-fired units increase significantly with an increase in carbon costs. The CCGTs generate electricity at a very competitive price when they are highly loaded. However, when the units operate with a low output, the coal-fired plants can be cheaper than the CCGTs.

- Estimation of MEFs without considering carbon costs is likely to seriously underestimate the carbon savings that can be achieved, as carbon costs can drive heavy polluters to work on the margin and respond to the DSUC.

- Utilization level of generators should be considered in MEF assessment, especially in summer case when the electricity demand is relatively lower. Otherwise, both carbon emissions savings and FCC savings are to be underestimated.

- The MEFs are sensitive to the level of demand reduction, particularly when the reduction is small. However, the MEFs are much more stable in 5% and 10% demand reduction scenarios.

- The new merit order method projects the MEFs to increase over the next ten years, due to heavy polluters being assumed to take response. It is a more plausible estimation of future carbon efficiency because the increase of future carbon price will drive heavy polluters to work on the marginal and respond to marginal changes in the system.

Chapter 6

Marginal Emissions Factor with Network Constraints

THIS chapter extends MEFs estimation from energy aspect to power network and analyses the possible MEFs changes due to system constraints.

6.1 Introduction

Network constraint in system operation is somehow inevitable. Its impact on Marginal Emissions Factor is possible where network capability is not enough to implement all the generations expected by the pre-assigned merit order. Therefore, it might result in generators with high rank in merit order being prevented from responding and alternative generators being activated to take the transferred power. It is necessary to examine the impacts of network constraints on MEF estimation, although none of the existing works about MEFs takes this into consideration.

In this chapter, the estimation of MEFs is to extend from energy aspect to electric network. The commonly used fuel-cost-based MEF is applied in two test systems to examine how MEFs can change with location and also to analyze the possible MEFs changes due to system constraints. Non-congested scenario and Congested scenario are also implemented to give a better understating of how the MEFs are affected in practical power system. Three demand reduction scenarios are used to see the possible overestimation or underestimation of the conventional fuel-cost-based MEF without considering network constraints.

6.2 Network Congestion

6.2.1 Definition of Network Congestion

The Electricity Supply means electricity needs to be delivered from generators to customers. Theoretically, it is very optimal to place the generation sites in the demand center, as the power losses is the minimum and security of supply is the maximum. In practice, it is extremely difficult to build up power plants in demand center if not impossible, for the reasons such as limited space in urban area and environmental problem. So a suboptimal choice has to be made that generation sides are placed according to location of the source or national security, and electricity is then transported from generation side to demand side through the electricity network.

An electricity network is an interconnection of power transformers, high-voltage transmission circuits that carry electricity from distant generation sites to demand centers and distribution circuits that connect individual customers [90]. Whenever a particular element on the network reaches its maximum capacity of delivering power, no additional power can be added to this element and the network is congested. “Congestion” is what happens when there is a bottleneck somewhere on this network [90-92]. This bottleneck or constraint can refer to an operational limit imposed to protect reliability, or to a lack of transmission capacity to deliver electricity from existing or potential generation sources without violating reliability requirements [91].

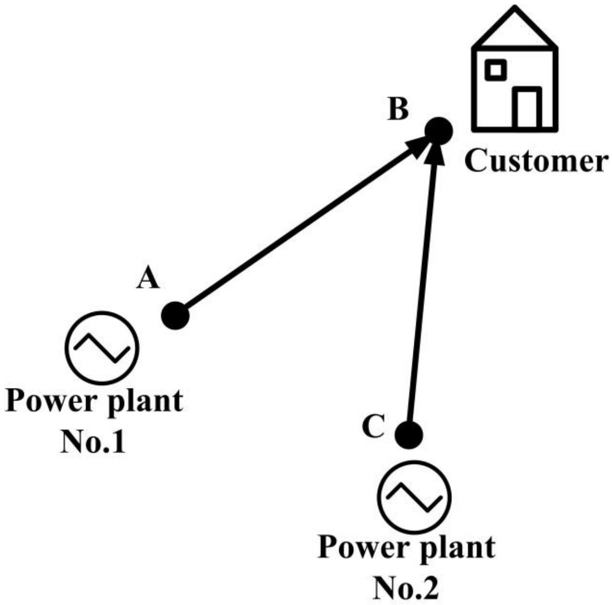

Figure 6-1 A simple example of electricity supply

For example, if electricity needs to be delivered in a simple network (Figure 6-1) from point A (generation side) to point B (demand side). Electricity flows across the network, taking the path from A to B. However, if the capacity of path A-B is not enough for transporting electricity to the customer, the supply is at stake because power flows have to obey certain laws of physics. There are two solutions available in this case. One is to reduce the customer’s demand to be less than the capacity of path A-B so that the balance can be kept. But if demand is assumed to be fixed and must be met, an alternative route has to be used, that is using another power plant (point C) to make up for deliveries that cannot be executed as planned beforehand.

In a word, congestion is a consequence of certain facts that no element has unlimited capacity of delivering electricity, and that electricity has to be used up as soon as it is generated.

6.2.1 Potential Impacts on MEF

Congestion has its impacts on changing the pattern of electrical flow and in particular affecting the carbon emissions in power system. In terms of estimating Marginal Emission Factor, it can prevent generators being activated according to the prearranged order and thus affect the MEFs.

As explained in Figure 6-1, if the network is congested, additional electricity has to come along an alternative route and from an alternative source of supply. It is highly possible that such alternative source (another generator) is not the next in the merit order. For example, if power plant No.1 is more expensive than power plant No.2, under a cost-base merit dispatch, plant No.1 should take response first when the demand is changed. However, there is a possibility that plant No.1 might not be able to respond because path A-B is congested. If that is the case, alternative option has to be taken and plant No.2, which could be the last resort in the order, needs to step in and take the response as the demand must be balanced. When this situation occurs, the results of estimating MEFs without considering network constraints are no longer valid.

Furthermore, previous researches on MEFs use a single average value of power losses to consider the impacts of network. They assume the MEFs to be the effects of marginal plants plus an increase (around 7%) by power losses. However, such assumption is flawed because all the locations in the network are assumed to experience the same level of power losses. No locational difference is reflected from such model. Theoretically, if a demand change happening at any location of the network results in the same effects on power losses, this assumption could be valid. If that is not the case, the assumption is questionable.

In practice, it is not possible that each point of the network has the same sensitivity to power losses. Demand points that are far away from generators might cause more power losses while those who are close might cause less. Such differences in power losses can result in different MEFs as power losses is one of the main contributors to MEFs.

Basically, locational analysis of marginal carbon emissions is necessary. If the MEFs do not change with different location in a network or the change is trivial, one single MEF for a whole network is valid. If not, details need to be taken into account to make sure the demand response being applied at the optimal location to achieve the best carbon reduction.

6.3 Assumption of Local Energy Sources

According to the discussion in last section, plant No.2 can replace plant No.1 to take demand response when the system is congested. Such replacement is against the merit order dispatch and against the merit order based MEFs. The MEFs can thus be altered. The question is: how much alteration can the MEFs be affected when such replacement happens?

Basically, the alternative generator in this case is the generator that are closer to the demand, the plant that are constrained less by the network. These less-constrained generators could be the coal-fired, CCGT units or distributed generation (DG).

Distributed generation is and will be playing an important role in delivering sustainable and affordable energy. Currently, distributed generation represents around 11 per cent (nine gigawatts) of the GB's generating capacity, but this number will rise as deployment of renewables and combined heat and power (CHP) increases and the GB moves towards a decarbonized power sector [93-94]. They are either zero-carbon or low-carbon technologies. Generating technologies that make up a significant proportion of distributed generation in the GB include solar, wind, and combined heat and power [93]. Some of the technologies are intermittent, but others are flexible and controllable. If output of the technology is controllable, the DG can be used to take flexible demand and be the alternative generator when other generators are constrained. In such a case, the marginal carbon emissions can be reduced to some extent depending on how much the generation is replaced.

The coal power station burns coal to boil water and drives a steam turbine by the produced steam to generate electricity. It is nearly the least efficient and most polluting of all types of power station in the GB system. If the coal-fired is the alternative generator, the MEFs can be driven to the worst case – the most polluted scenario. If the replacement is taken by CCGT units, the MEFs are something in between as the CCGT is neither the most polluted technology nor the cleanest technology.

In order to represent a plausible range for MEFs' changes with different replacements, two scenarios are considered in the following demonstration, which the coal-fired replacement and the DG replacement.

6.4 Merit Order Model Considering Locations

To grasp the impacts of demand side on carbon emission, start-up criteria is needed to determine which plants have the priority to meet the demand change in a power system. Based on the assumption that generators with highest fuel costs are desirable for balancing demand response, the generating plants are ranked according to the following equation to dispatch:

$$Rank = \min\left\{FC_1, FC_2, \cdots, FC_i, \cdots, FC_N\right\} \tag{6-1}$$

Where, FC_i refers to fuel cost generator i. On the other hand, instead of applying a 7%-8% top-up rate (network loss) to the marginal emissions to obtain the results of MEF, the marginal emissions are assessed at different locations of the power network. Flow chart of assessing MEFs with locational considerations can be summarized as:

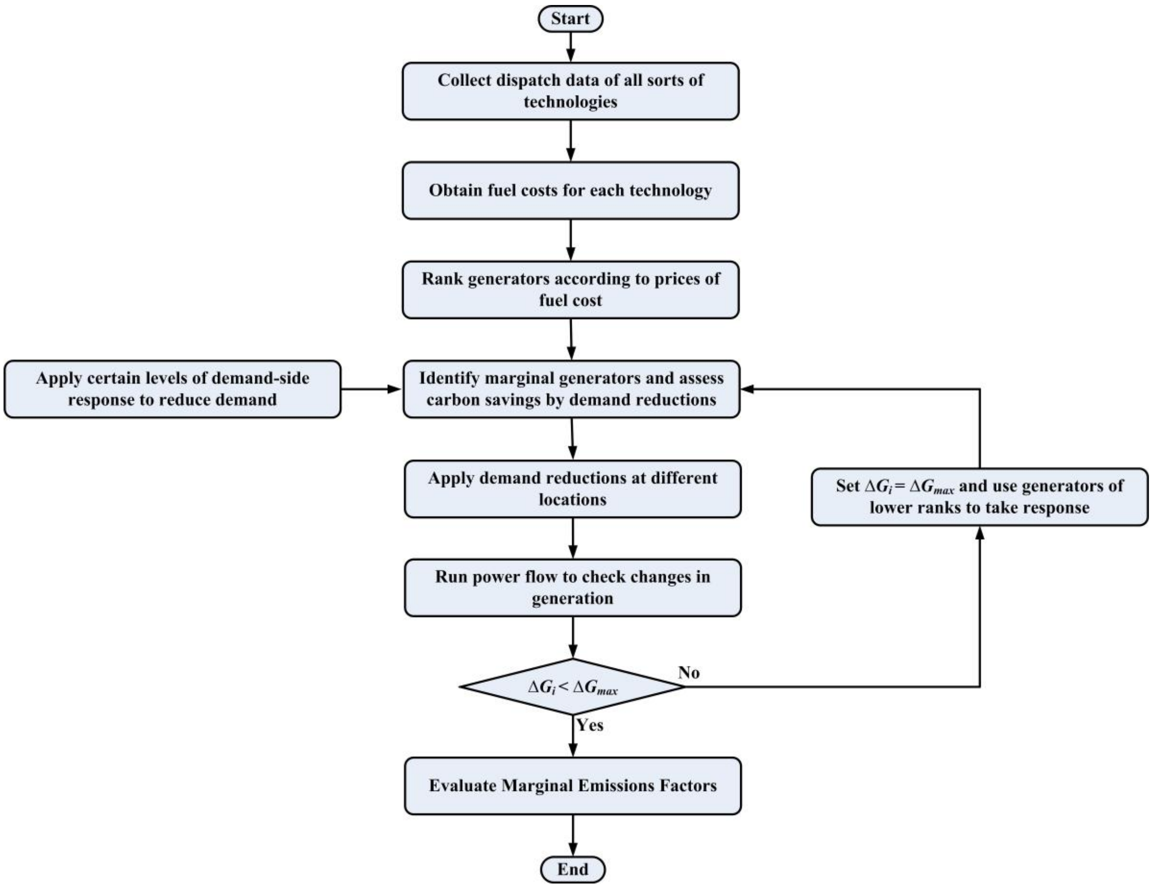

Figure 6-2 Flow chart of locational MEFs

6.5 Case Study I: IEEE 14-bus System

In this section, a fuel-cost-based merit order is applied in the IEEE 14 buses test system to see how much the MEFs might be affected by system constraints. The test system has 4 generators, 14 buses and 20 branches, with a total active power of 258.8 MW. The structure of IEEE 14-bus system is shown in the following diagram (Figure 6-3). It is a system without identifying generation technologies. In order to set up a proper study for carbon assessment, specific technologies are allocated to the generators in IEEE 14 system so that its carbon emissions level is the same as the GB rate (around 0.50 kg CO_2 per kWh). The main flexible power plants are assumed to be located in node 1 (Pump storage), node 2 (the coal-fired), node3 (CCGT) and node 6 (OCGT). Analysis of system impacts are then set up in two scenarios:

- Non-congested Scenario - where all the branches operate below their original ratings;

- Congested scenario - where part of the branches reaches their ratings and power flow needs to be balanced by alternative routing.

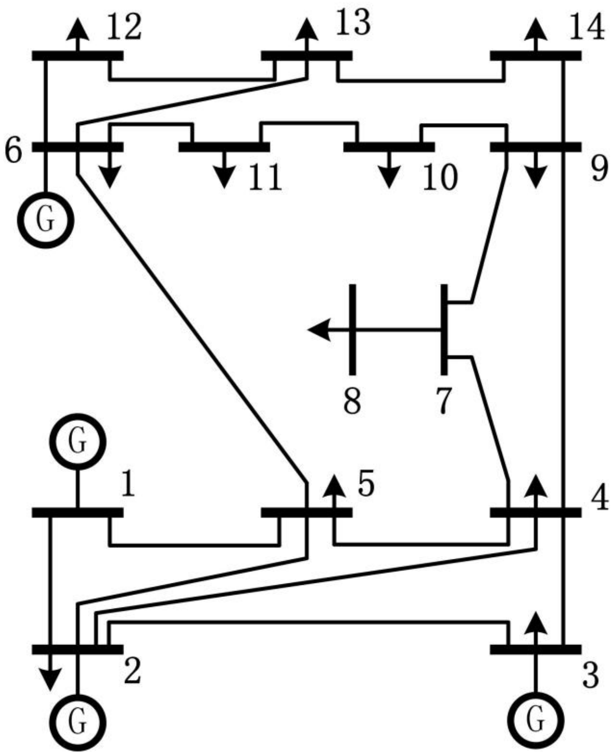

Figure 6-3 Generator-to-Demand system (IEEE 14-bus system)

For the reason of convenience, this system is called as "Generator-to-Demand system". It implies that sort of system in which generators located mainly on one side of the system are connected with demand via one or two branches only. It is different from that sort of system in which demand changes can be balanced locally.

Based on pre-simulations of power flow, it shows that, if the system demand increases, the first branch operation above its rating is Branch 9-14 when the increase is around 10 % of system demand (25.88 MW). Therefore, all nodal points in the system are assumed to experience three levels of demand changes (+1%, +5%, and +10%). Relevant MEFs are obtained from the results of the simulations, which are compared with the conventional fuel-cost-based MEFs that do not take into account locational differences of the system.

6.5.1 Non-congested Scenario

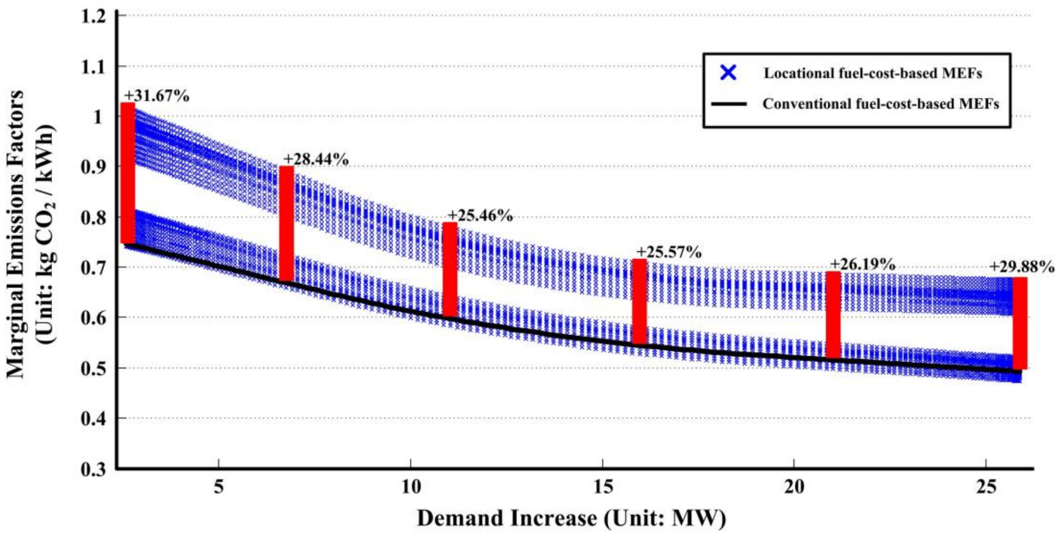

Figure 6-4 Comparison between locational MEFs and the conventional MEF

According to figure 6-4, it can be seen that the MEFs might be underestimated up to 30% if the system constraints are not applied. When the electricity demands are changed, the conventional fuel-cost-based method estimates a single value for the marginal change based on a pre-assumed merit order. The value is estimated by the average power loss of the system (such as 7.5%). However, demand changes at different points of the system have no consistent impact on power losses. Even if the same demand change is applied, the change at remote area results in bigger change in power losses because electrical distance between the marginal plants and the remote area is much longer. According to the law of physics, longer electrical distance of transporting energy means bigger power losses associated. Bigger power losses lead to more carbon emissions and an increase of Marginal Emissions Factors. In this study, such an increase can add up to around 30% when the demand change happening at the remotest point of the system (Node 14).

In Figure 6-5, the relation between MEFs and power losses is highlighted. It is clear that when the demand changes are applied to the test system, the overall profile of increase in MEFs is very similar to that in power losses. This is because the marginal plants are not reshuffled. When the system is not congested, the expected merit order dispatch is applicable. The merit order is not reshuffled. The differences in electrical distance mean different generation outputs from marginal plants. The MEFs are not changed fundamentally, but affected with a multiplier depending on how much an additional power loss is created.

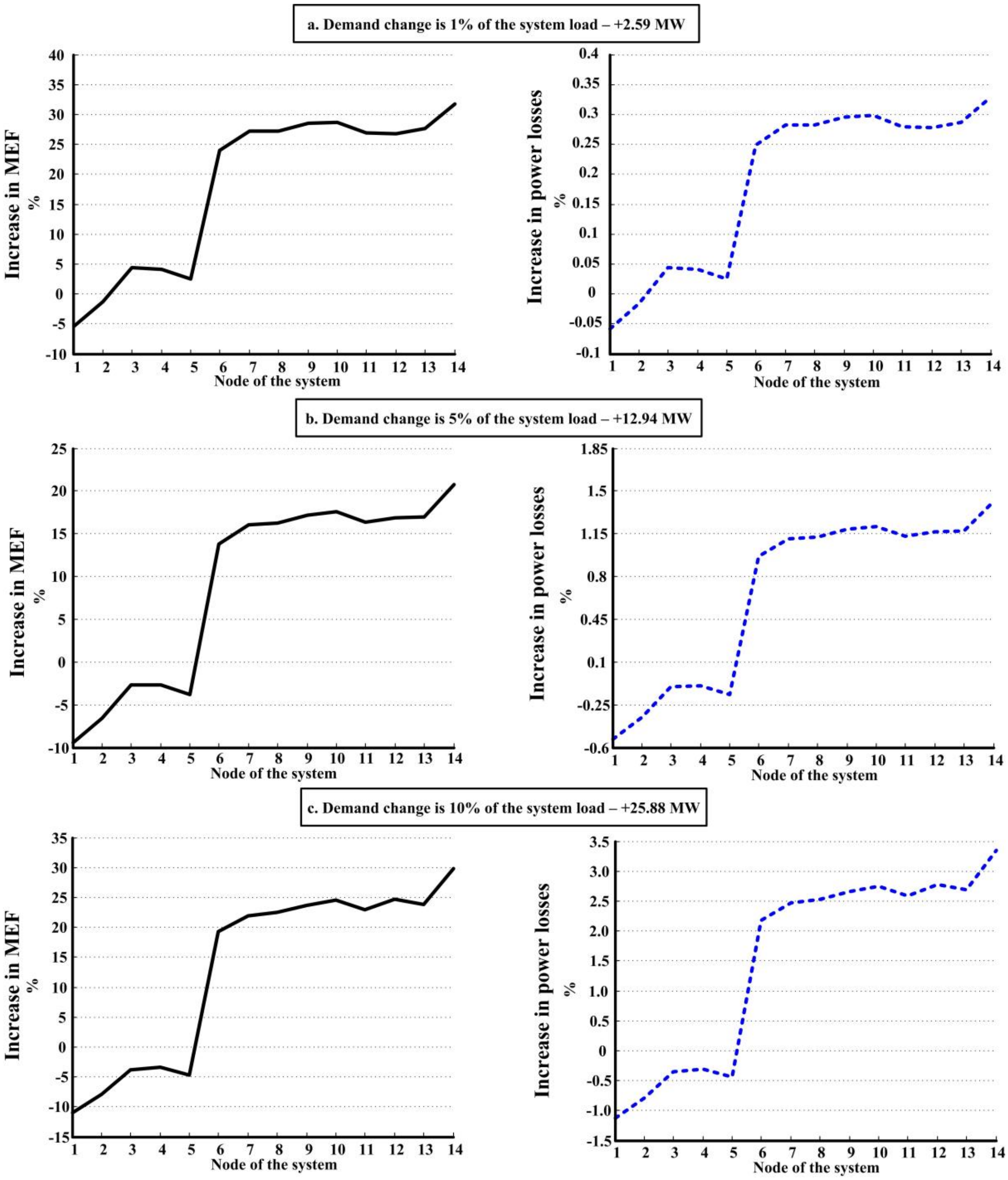

Figure 6-5 Locational MEFs and marginal power losses

6.5.2 Congested Scenario

In order to set up a congested scenario to see how MEFs might be changed when system is congested, capacities of three branches are halved in this study, Branch 4-7, Branch 4-9 and Branch 5-6. They are the main branches delivering electricity from the generation side to the demand side. The maximum power flow deliverable by them are reduced to the half, reduced from 46.2 MVA to 23.1 MVA for Branch 4-7, reduced from 46.2 MVA to 23.1 MVA for Branch 4-9, and reduced from 61.1 MVA to 30.6 MVA for Branch 5-6.

On the other hand, when the system is congested, no more power flow can be transferred from the generation side to the demand side. An increase in demand leads to the imbalance of system. Therefore, another assumption has to be made in this study that is when the electricity cannot be supplied from the remote generation side, a local generator (Generator at node 6) is activated to balance the electricity supply.

Based on simulation results of power flow, it can be seen that when demand increase is around 13 MW, part of the system is congested (Branch 4-7 and Branch 4-9) and electricity supply needs to be balanced by a local generator that is closer to customers. If this local generator is the coal-fired, the result is an increase in MEFs (Shown in Figure 6-6).

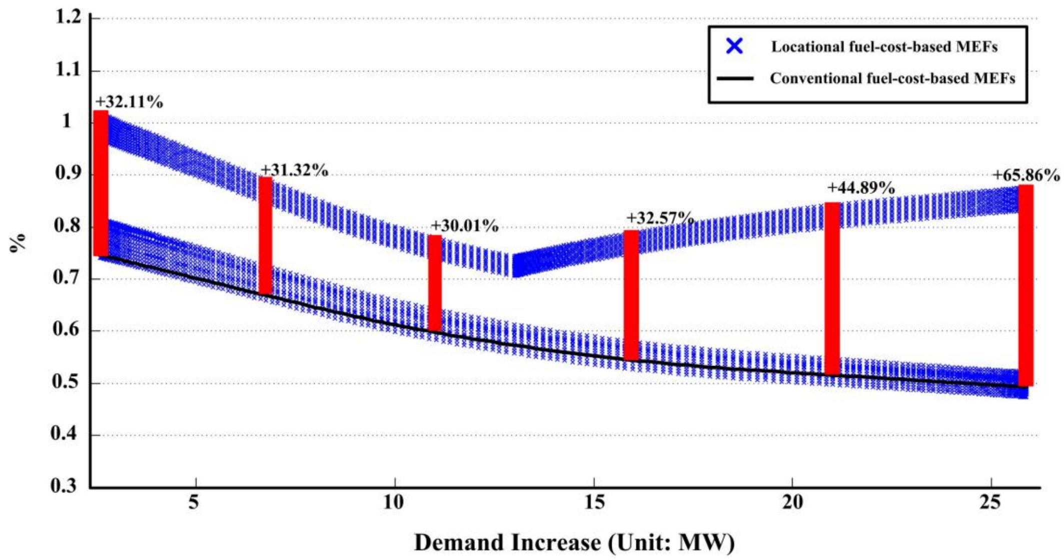

Figure 6-6 Local coal-fired plant taking response when system congested

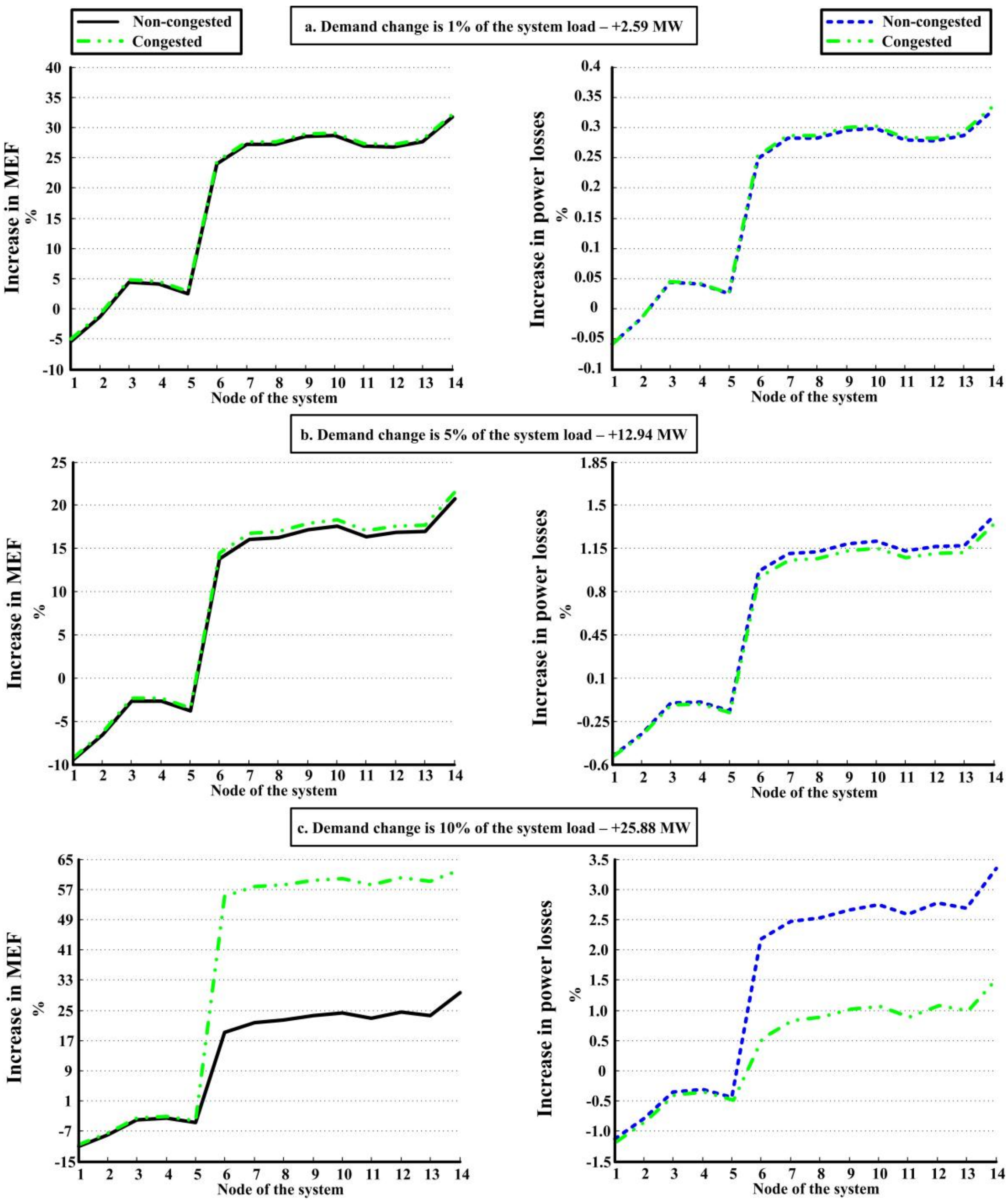

Figure 6-7 Locational MEFs and marginal power losses, coal-fired case

As shown in Figure 6-6, when the demand change exceeds 13MW, the system impacts on MEFs become bigger due to a heavy carbon polluter being activated to take demand response. In the worst case that is the 10% demand increase happening at the remotest node (node 14), estimating MEFs without considering system impacts can lead to an underestimation of around 65.86%. It means that increasing demand at such a remote point triggers much more carbon emissions than the increases in the vicinity of marginal plants. It also points out the deficiency of conventional MEFs method in detecting locational difference and the necessity of considering network constraints when assessing a wide-area electricity grid.

If this local generator is a clean generation technology like the Distributed Generation, the MEFs change in a very different way (Shown in Figure 6-8). It can be seen that when the system is congested (demand increase is around 13 MW), the local DG steps in to balance the demand. Because the DG is a carbon-free assumed technology, acting as a marginal plant in this study. Further demand increase leads to a decrease in MEFs. In such case, estimating MEFs without considering system impacts can lead to an overestimation of around 18.70%.

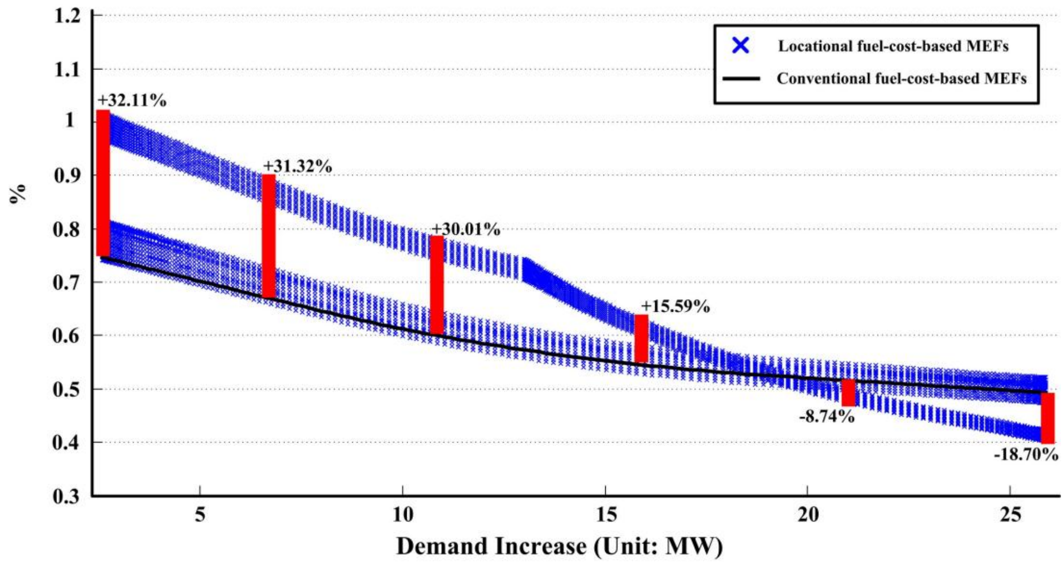

Figure 6-8 Local DG taking response when system congested

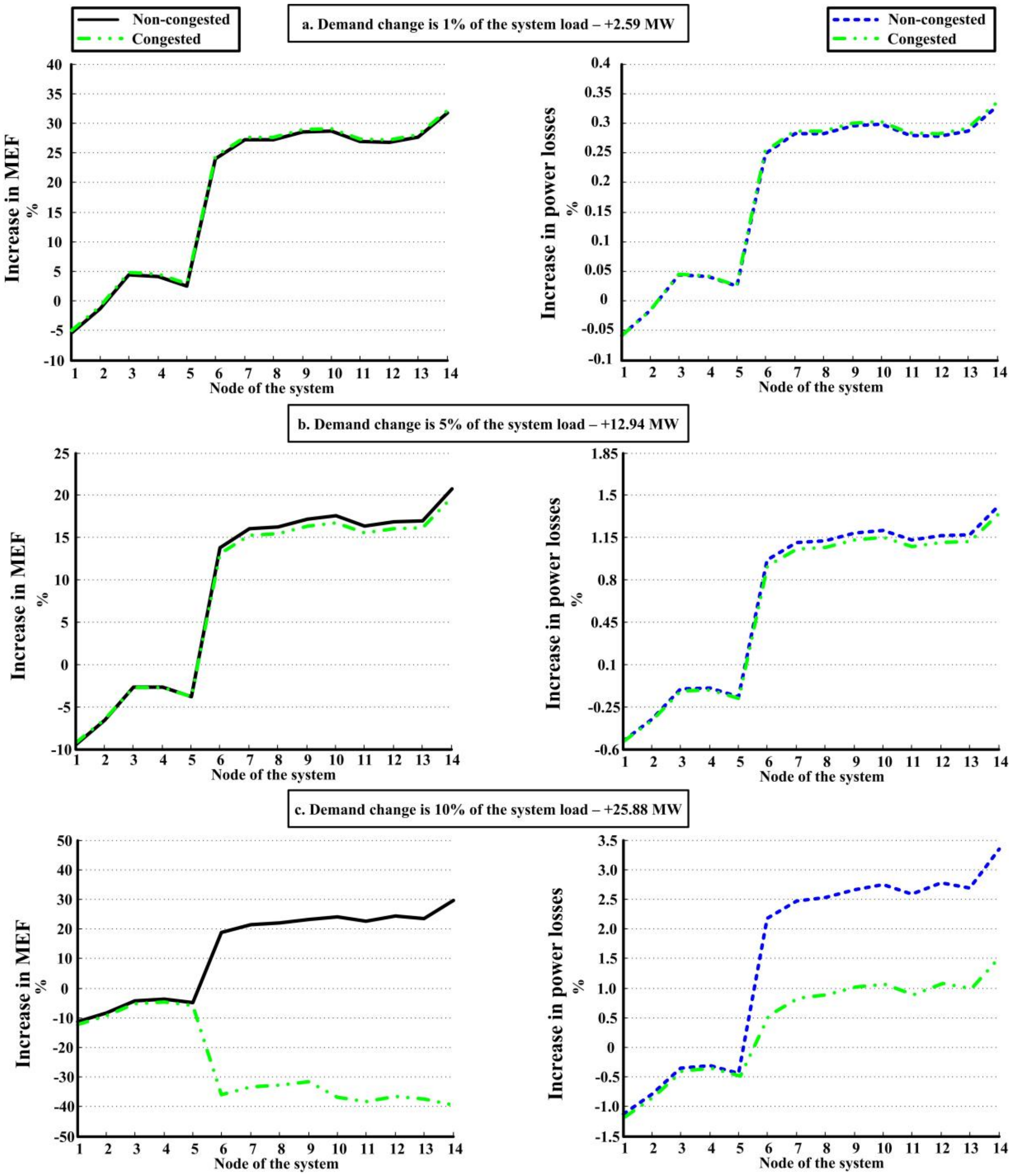

Figure 6-9 Locational MEFs and marginal power losses, DG case

6.6 Case Study II: A Multi-area Power System

In last section, results have shown that if the demand change is applied to different points of the system, the MEFs would vary with the locations. However, according to Figure 6-4, there is a gap clearly shown between the two areas. One of the areas is where the marginal plants stand and the other is close to demand centre. The fact is that differences of MEFs between the areas are much wider while the differences within the same group of area are much smaller. Therefore, an argument might be able to be drawn, if the marginal plants are mainly located on one side of the network rather than being distributed throughout the power system, areal MEFs are plausible if locational or nodal MEFs are too different to obtain. However, there is a question in such argument, that is, if it is a multi-area power system and marginal plants are distributed across all areas, what the MEFs might be like?

In order to test the MEFs in a multi-area power system, a 59-bus system is used in this system [95] (Figure 6-11). The model of this system is based on the southern and eastern Australian networks. It is divided into 5 areas where most of electricity demands are located in area 2 and area 3. The system has 92 branches, 23 generators, 70 Two-Winding transformers, 22300 MW active power demand and 2462 MVar reactive power demand. In steady-state operating condition, the total generation is 23030 MW and power loss is 3.27%. The Parameters of the system are listed in Appendix 1.

To test the Marginal Emissions Factor in this system, all nodal points in the system are assumed to experience demand changes from +1% (233MW) to 10% (+2230MW), the same assumption as made in previous section.

An important assumption in this study that can have a big impact on the output of MEFs is the allocation of marginal plants. In last section, the situation is examined where generators in the system are mainly located on one side of the system while the demand is largely located on the other. It is a typical example of supplying electricity for practical networks. However, there are some other networks where generators are distributed across the system and customers consume the electricity that is generated mainly from areal generators. Therefore, another assumption is made in this case that one or two power plants within each area is selected as marginal plants and if the demand change is too significant to be balanced by areal marginal plants, additional power is assumed to come from marginal plants of nearby area.

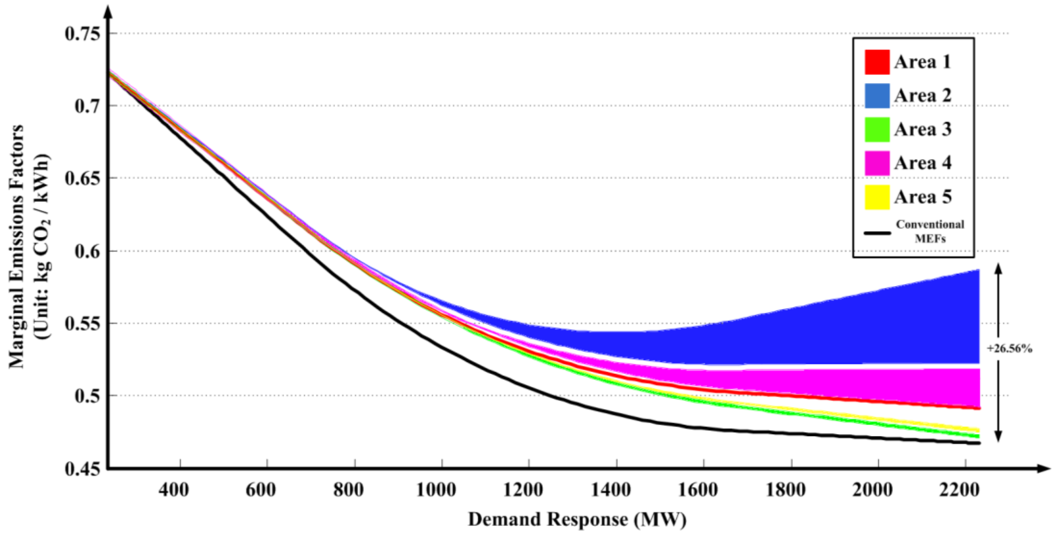

Figure 6-10 locational MEFs in a multi-area power system

According to Figure 6-10, in a multi-area power system where marginal plants are distributed across all areas, locational difference or areal difference is insignificant when the demand change is small. This is due to the demand changes being balanced locally by areal generators. Based on the analysis in previous section, if the demand change is balanced locally, no significant increase would happen in power losses. So MEFs at any location of the system turn out to be close to the conventional MEFs. Presumably, an additional increase of around 5% on top of the conventional MEFs could be an evaluation of system impacts in such a case. However, if the demand response is too big to be balanced by areal generators, that is not the case anymore.

It is shown in Figure 6-10 that when the demand response is significant, the system impact can lead to 26.56% increase in MEFs, compared with the conventional MEFs that do not take into consideration the system impacts. The reason is that, if demand changes need to be balanced by generators in other areas, the electrical distance between the point of demand response and the marginal plants become much longer. Long electrical distance means big power losses, thus leading to significant increase in MEFs. However, it is noticeable that MEFs of big demand changes divide into several area-based groups, which is consistent with the results of previous section. It verifies the argument that for a large-scale system, if locational or nodal MEFs are too different to obtain, complexity can be reduced by assessing MEFs on an area basis.

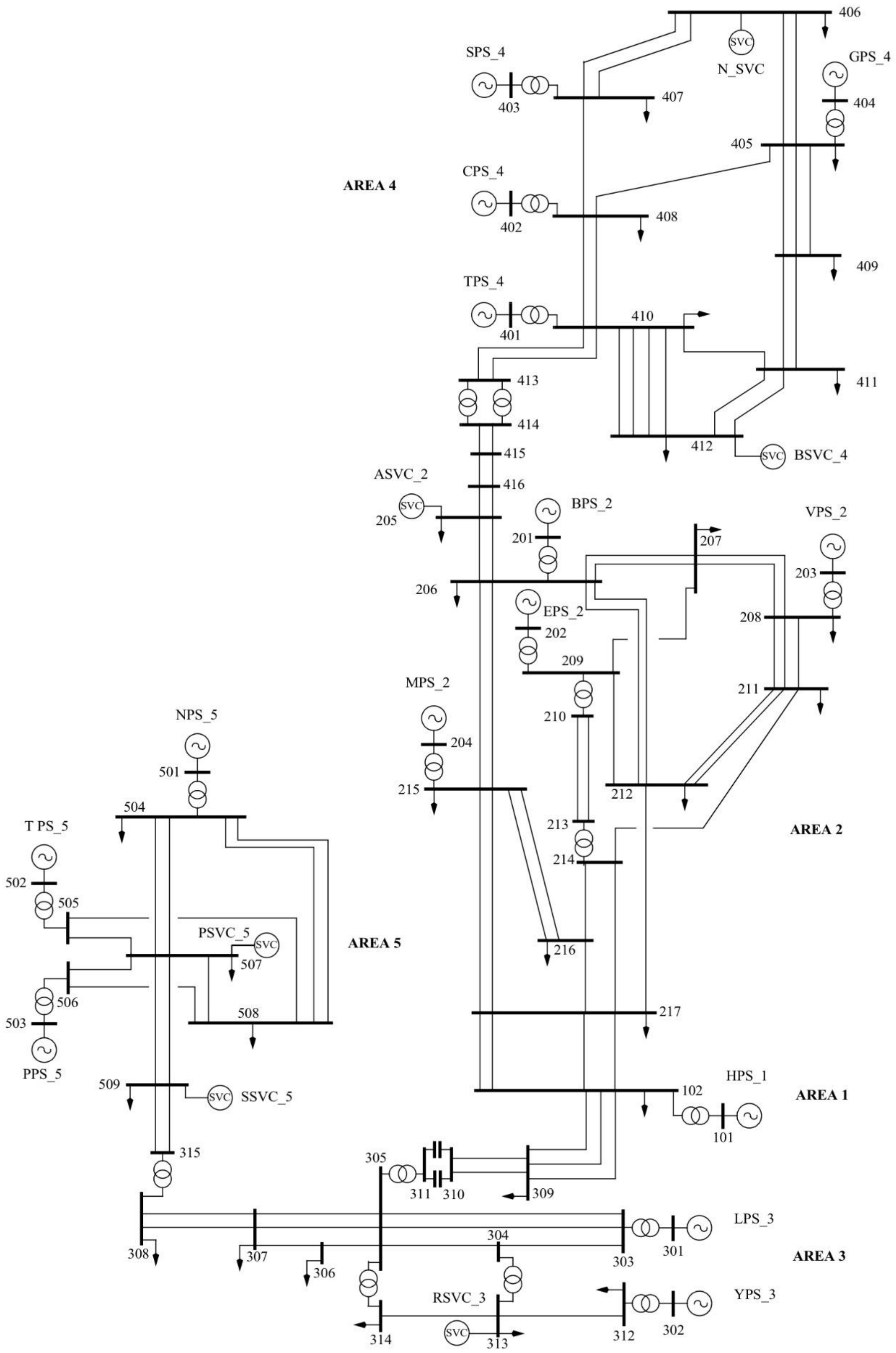

Figure 6-11 A example of multi-area power system

6.7 Chapter Summary

The main target of this chapter is to extend the MEF estimation from the energy aspect to power network. In order to see how MEFs might change with different location, two typical test systems are used in this study. One is a system where marginal plants are mainly located on one side of the network and demand is long electrical distance away. The other is a multi-area power system where marginal plants are distributed across all areas. Based on the simulation results, some conclusions can be drawn as:

- In a Generator-to-Demand system, the conventional method of estimating MEF without considering network impacts can underestimate the MEFs by up to 30%. This is because the electrical distance between the marginal plants and the most remote area is very long. Demand change at remote area results in a big change in power losses. Bigger power losses lead to more carbon emissions and an increase of Marginal Emissions Factors.

- The MEFs can experience significant changes if there is congestion in the system. This is due to local generators being activated to balance demand and generators responding order reshuffled. However, whether this reshuffle leads to an increase or a decrease in MEFs depends on the type of the generator taking imbalanced power.

- In a multi-area power system where marginal plants are distributed across all areas, locational difference or areal difference is insignificant when the demand change is small. This is due to the demand changes being balanced locally by areal generators. However, if the demand response is too big to be balanced by areal generators, the MEF is driven higher due to the increase in power losses.

- In a multi-area power system, if locational or nodal MEFs are too different to obtain, complexity can be reduced by assessing MEFs on an area basis - one MEF estimation for each area.

Chapter 7

Conclusion

THIS chapter summarizes the thesis by outlining the major contributions and findings from the research.

The Power sector is the single largest source of carbon emissions around the world, accounting for 25.9% of global carbon emissions. Decarbonization of the power sector is important for the transition to a sustainable and low-carbon world economy. Proposed strategies of decarbonizing the power sector consider both the supply side and the demand side. On the supply side, generation will be decarbonized through the application of low-carbon technologies like the renewable and the nuclear power. Mechanisms like carbon taxes or emission trading schemes, will be introduced into the power market to control the greenhouse gas emission. On the demand side, electric vehicles will be deployed to electrify the transport system and smart grids will be set up to encourage customers to take more active response. However, estimating the potential carbon benefits from demand-side response is the key step for the improvement of energy efficiency and for encouraging the DSUC as a carbon reduction tool. There is a need to conduct an objective assessment of carbon efficiency in the power sector so as to grasp the impact of demand-side changes and evaluate its potential environmental benefits.

There are currently two types of tools commonly used in the power industry to evaluate the impacts of DSUC regarding carbon emissions namely Average Emissions Factor (AEF) and Marginal Emissions Factor (MEF). However, the commonly used accounting model of estimating AEF, based on statistical data, lacks clarity on the factors actually affecting the estimation. Studies on MEF attempted to develop a merit order of dispatch according to specific criteria such as the cost-based criteria and the utilization-based criteria. Nevertheless, the MEF estimation can be improved by considering key technical limits such as ramp-rate constraint, impacts of carbon mechanism on the dispatch order, and by differentiating MEF estimation with locations due to electric network constraints. Therefore, this work has carried out intensive research in the improvements for both the AEF and the MEF, so as to tackle the shortcomings of the existing estimations.

Estimating AEF by Factors That Affect Emissions

In order to assess the carbon footprint of electricity consumption, a novel model is proposed that is based on four important factors affecting carbon emissions in power sector, namely, carbon efficiency of different generation technologies, energy mix of power sector, power losses and potential indirect emissions such as fuel exploration and fuel transport. British electricity system is used to test the validity of this approach. Three future scenarios are used to project GB's AEF until 2032. AEFs of China and US are also assessed to analyze the current footprint levels of different countries. Conclusions can be summarized as:

- Based on the demonstrations, the proposed method is proved to be effective in estimating Average Emissions Factors over a long-time framework. By training the parameters of the model with the historical data, its estimations for AEFs can be further improved.

- Demonstrations in future scenario show that the GB's carbon footprint in power sector will be decreased by 68 per cent by 2032 according to the Accelerated Growth Energy Mix, and decreased by 58 per cent by 2032 according to the Slow Progression scenario. Approximately, 1% of increase in renewable generation is leading to 0.7% of decrease in carbon footprint in this study.

- Comparisons of AEFs among GB, US and China show that the GB is leading the way in power sector on combating climate change. As the GB relies much less on coal than the US and China, the carbon footprint of GB's power sector is cleanest among the three countries.

Considering Technical Constraint in MEF Estimation

To tackle the ignorance of technical constraint in MEF estimation, the fuel-cost-based merit order is reshuffled by considering ramp-rate constraint for generators. The reason for this improvement is that expecting power plants to be ramping without ramp-rate constraint is impossible. The proposed method is applied into British electricity system to illustrate the differences between the AEF and the MEF in GB. Two conventional merit order approaches of estimating MEF (utilization-level-based and fuel-cost-based) are compared with the MEF with ramp-rate constraint. Moreover, sensitivity analysis of MEFs to a few scenarios of fuel price is made to see how MEFs might change with different prices. Conclusions can be summarized as:

- All previous studies have argued that MEF is higher than system-average rate and application of AEF into marginal impact assessment can lead to significant underestimation of emission savings. However, demonstrations in the GB electricity system showed that the MEF can be lower than the AEF when low-carbon generators working on the margin and being triggered by demand response.

- Case studies show that MEFs display a high degree of variability over the course of a year and over the course of a day. Therefore, a fixed marginal factor for both peak and off-peak times is not justified, i.e. a single marginal emission cannot provide adequate reflection of the potential carbon savings from demand response for each time period during a day.

- Case studies show that fuel-cost-based MEFs and utilization-based MEFs obtain similar estimation during the night time, but their differences in estimating MEFs during the peak time is significant, especially in the winter scenario.

- When the demand reduction is small, impact of generators' ramp rate on the estimation of MEF is trivial as the flexible generator has enough capability to balance the reduction. But if the demand reduction is bigger than the ramping ability of the coal-fired generators, such as 5% and 10% in the demonstration, the ramp-rate constraint has a big major impact on MEF and consideration of the ramp-rate constraint in the dispatch order becomes indispensible.

- The fuel-cost-based MEFs are subject to the fuel price considered. The MEFs in the past price scenario are much higher than the MEFs in the current price scenario. However, for the future price scenario, the MEFs based on fuel cost order are the same as the current price scenario because the price of gas is always much more expensive than that of coal.

- Case studies show that increasing the MEF by triggering heavy carbon polluters to work on the margin is possible, which illustrates the importance of introducing carbon mechanism to the power sector. The point is that if the carbon prices introduced can make low-carbon technology become competitive in generation, the environmental benefit by Demand-side response is also enhanced.

Evaluating Marginal Emissions Factor with Carbon Mechanism

The conventional merit order based MEF approach assumes the most expensive generators (fuel costs) are on the margin for a given system loading level and then calculates the marginal change in CO2 emissions as a result of demand change. However, the fuel cost of each generation technologies is assumed to be fixed, and the utilization level of generators is thus not factored into the fuel cost. Further driver to a new MEF approach is the introduction of carbon price, where the most expensive generator can no longer be solely decided by the fuel cost. For example, the coal-fired units are cheap in fuel but very expensive in carbon emissions, thus they need to be curtailed first when demand reduction takes effect. Therefore, in a low carbon energy system, both the utilization level of generators and the carbon costs must be considered in MEF assessment, and a new merit order based approach is needed to improve the traditional MEF estimation.

To tackle this problem, a method of internalizing emission as a part of generation cost is proposed to assess the impact of carbon cost on the generators' profile. Taking into consideration generator's utilization level, it assumes generators are dispatched according to the summation of minimal fuel costs and carbon costs. Conclusions can be summarized as:

- With a carbon mechanism, the costs of coal-fired units increase significantly with an increase in carbon costs. The CCGTs generate electricity at a competitive price when they are highly loaded. But when the units operate with a low output, the coal-fired plants can still be cheaper than the CCGTs.

- Estimation of MEFs without considering carbon costs is likely to seriously underestimate the carbon savings that can be achieved, as carbon costs can drive heavy polluters to work on the margin and respond to the DSUC.

- Utilization level of generators should be considered in MEF assessment, especially in summer case when the electricity demand is relatively lower. Otherwise, both carbon emissions savings and FCC savings are to be underestimated.

- The MEFs are sensitive to the level of demand reduction, particularly when the reduction is small. But further demand reduction can result in relatively stable MEFs.

- The new merit order method projects the MEFs to increase over the next ten years, due to heavy polluters being assumed to take response. It is a more plausible estimation of future carbon efficiency because the increase of future carbon price will drive heavy polluters to work on the marginal and respond to marginal changes in the system.

Considering Network Constraints in MEF Estimation

Network constraint in system operation is somehow inevitable. Its impact on Marginal Emissions Factor is possible where network capability is not enough to implement all the generations expected by the pre-assigned merit order. Therefore, it might result in generators with high rank in merit order being prevented from responding and alternative generators being activated to take the transferred power. It is necessary to examine the impacts of network constraints on MEF estimation, although none of the existing works about MEFs takes this into consideration.

To tackle the problem of network impacts, the commonly used fuel-cost-based MEF is applied in two test systems to examine how MEFs can change with location and also to analyze the possible MEFs changes due to system constraints. The used two test systems are very carefully modeled to represent the typical system of electricity supply. One is a system where marginal plants are mainly located on one side of the network and demand is long electrical distance away. The other is a multi-area power system where marginal plants are distributed across all areas. Based on the demonstrations, conclusions can be summarized as:

- Results show that the conventional method of estimating MEF without considering network impacts can underestimate the MEFs by up to 30% in a Generator-to-Demand system. This is because of long electrical distance between the marginal plants and the most remote area. Demand changes at remote area results in changes in power losses that higher than the system average power loss, leading to more carbon emissions and an increase in MEFs.

- The MEFs can experience significant changes if there is congestion in the system. This is due to local generators being activated to balance demand and generators responding order reshuffled. But whether this reshuffle leads to an increase or a decrease in MEFs depends on the type of the generator taking imbalanced power.

- In a multi-area power system where marginal plants are distributed across all areas, locational difference or areal difference is insignificant when the demand change is small. This is due to the demand changes being balanced locally by areal generators. However, if the demand response is too big to be balanced by areal generators, the MEF is driven higher due to the increase in power losses.

- In a multi-area power system, if locational or nodal MEFs are too different to obtain, complexity can be reduced by assessing MEFs on an area basis - one MEF estimation for each area.

Chapter 8

Future Work

T **HIS** chapter proposes some future works that can be done to improve carbon assessment for energy system, as well as its interaction with other researches on lower carbon technology.

Integration with Other Sectors to Reduced Carbon Emissions

This thesis focuses on carbon assessment in power sector. However, no matter how important it is to reduce carbon emissions in power sector, other sectors like transportation sector are undoubtedly essential as well for low-carbon future. There should be a proper analysis of assessing carbon emissions across multi-sectors, so as to figure out the best routine of securing a sustainable and low-carbon future.

Practically, not only the railway system is going to be electrified, but also vehicles and heating are said to be electrified in future. Electrifying the vehicles or rail system would reduce carbon emissions in transportation system to nearly zero, but it will transfer lots of energy usage from other sectors to the power sector. As a result, the power sector will either be overloaded or emitting loads of carbon emissions. Details need to be examined very carefully to maintain a good tradeoff between the transfer of energy usage and the potentials of reducing carbon emissions.

Integration with Dynamic carbon prices

The main target of this work is to improve the carbon assessment in the power sector so that the environmental benefit by demand response is enhanced. However, the results and conclusions obtained in this thesis can also be beneficial to other aspects such as carbon market. Carbon market is a developing market where money is exchanged for carbon allowance. The results and conclusions shown in this thesis are largely the information about power sector’s carbon emissions of daily-based, seasonal-based or locational-based. On one hand, the information can be used to design demand response strategy. On the other hand, it could be used to get a better trading deal for participants in carbon market.

Application of MEF in More Network Scenarios

In this study, the MEFs are tested in two typical power systems. One is a system where marginal plants are mainly located on one side of the network and demand is a long electrical distance away. The other is a multi-area power system where marginal plants are distributed across all areas. However, cases are much more complicated in reality. The MEF needs to be applied into more practical networks with extensive analysis before general conclusions can be made. Therefore, applications of MEF in network scenarios need to be carried on further in the future.

Appendix A

The 59-bus system network data:

A.1 Steady-state operating condition

	Load
Load Condition	Heavy
Total generation MW	23030
Total load MW	22300
Inter-area flows	(North to south)
Area 4 to Area 2 MW	500
Area 2 to Area 1 MW	1134
Area 1 to Area 3 MW	1000
Area 3 to Area 5 MW	500

A.2 Voltages at synchronous machine and SVC terminals for load flow

Bus No.	Voltage Mvar
205 SVC	1.055 -68.3
313 SVC	1.015 71.4
412 SVC	1.000 58.2
507 SVC	1.015 22.6
509 SVC	1.030 10.6

A.3 Transmission Line Parameters: Values per circuit.

From bus / to bus	Line No.	Line r+jx; b (pu on 100MVA)
102 217	1,2	0.0084 0.0667 0.817
102 217	3,4	0.0078 0.0620 0.760
102 309	1,2	0.0045 0.0356 0.437
102 309	3	0.0109 0.0868 0.760
205 206	1,2	0.0096 0.0760 0.931
205 416	1,2	0.0037 0.0460 0.730
206 207	1,2	0.0045 0.0356 0.437
206 212	1,2	0.0066 0.0527 0.646
206 215	1,2	0.0066 0.0527 0.646
207 208	1,2	0.0018 0.0140 0.171
207 209	1	0.0008 0.0062 0.076
208 211	1,2,3	0.0031 0.0248 0.304
209 212	1	0.0045 0.0356 0.437
210 213	1,2	0.0010 0.0145 1.540
211 212	1,2	0.0014 0.0108 0.133
211 214	1	0.0019 0.0155 0.190
212 217	1	0.0070 0.0558 0.684
214 216	1	0.0010 0.0077 0.095
214 217	1	0.0049 0.0388 0.475
215 216	1,2	0.0051 0.0403 0.494
215 217	1,2	0.0072 0.0574 0.703
216 217	1	0.0051 0.0403 0.494

A.4 Transmission Line Parameters: Values per circuit. (Continued)

From bus / to bus	Line No.	Line r+jx; b (pu on 100MVA)
303 304	1	0.0010 0.0140 1.480
303 305	1,2	0.0011 0.0160 1.700
304 305	1	0.0003 0.0040 0.424
305 306	1	0.0002 0.0030 0.320
305 307	1,2	0.0003 0.0045 0.447
306 307	1	0.0001 0.0012 0.127
307 308	1,2	0.0023 0.0325 3.445
309 310	1,2	0.0090 0.0713 0.874
310 311	1,2	0.0000 -0.0337 0.000
312 313	1	0.0020 0.0150 0.900
313 314	1	0.0005 0.0050 0.520
315 509	1,2	0.0070 0.0500 0.190

A.5 Transmission Line Parameters: Values per circuit. (Continued)

405	406	1,2	0.0039	0.0475	0.381
405	408	1	0.0054	0.0500	0.189
405	409	1,2,3	0.0180	0.1220	0.790
406	407	1,2	0.0006	0.0076	0.062
407	408	1	0.0042	0.0513	0.412
408	410	1,2	0.0110	0.1280	1.010
409	411	1,2	0.0103	0.0709	0.460
410	411	1	0.0043	0.0532	0.427
410	412	1 to 4	0.0043	0.0532	0.427
410	413	1,2	0.0040	0.0494	0.400
411	412	1,2	0.0012	0.0152	0.122
414	415	1,2	0.0020	0.0250	0.390
415	416	1,2	0.0037	0.0460	0.730
504	507	1,2	0.0230	0.1500	0.560
504	508	1,2	0.0260	0.0190	0.870
505	507	1	0.0008	0.0085	0.060
505	508	1	0.0025	0.0280	0.170
506	507	1	0.0008	0.0085	0.060
506	508	1	0.0030	0.0280	0.140
507	508	1	0.0020	0.0190	0.090
507	509	1,2	0.0300	0.2200	0.900

A.6 Transformer Ratings and Reactance

Buses		Number	Rating, each Unit (MVA)	Reactance per transformer	
From	To			% on Rating	per unit on 100MVA
101	102	g	333.3	12.0	0.0360
201	206	g	666.7	16.0	0.0240
202	209	g	555.6	16.0	0.0288
203	208	g	555.6	17.0	0.0306
204	215	g	666.7	16.0	0.0240
209	210	4	625.0	17.0	0.0272
213	214	4	625.0	17.0	0.0272
301	303	g	666.7	16.0	0.0240
302	312	g	444.4	15.0	0.0338
304	313	2	500.0	16.0	0.0320
305	311	2	500.0	12.0	0.0240
305	314	2	700.0	17.0	0.0243
308	315	2	370.0	10.0	0.0270
401	410	g	444.4	15.0	0.0338
402	408	g	333.3	17.0	0.0510
403	407	g	444.4	15.0	0.0338
404	405	g	333.3	17.0	0.0510
413	414	3	750.0	6.0	0.0080
501	504	g	333.3	17.0	0.0510
502	505	g	250.0	16.0	0.0640
503	506	g	166.7	16.7	0.1000

Appendix B

The IEEE 14-bus system network data:

B.1 Transmission Line Parameters: Values per circuit.

No.	From bus	To bus	r	x	b
1	1	2	0.01938	0.05917	0.0264
2	2	3	0.04699	0.19797	0.0219
3	2	4	0.05811	0.17632	0.0187
4	1	5	0.05403	0.22304	0.0246
5	2	5	0.05695	0.17388	0.017
6	3	4	0.06701	0.17103	0.0173
7	4	5	0.01335	0.04211	0.01064
8	7	8	0	0.17615	0
9	7	9	0	0.11001	0
10	9	10	0.03181	0.0845	0
11	6	11	0.09498	0.1989	0
12	6	12	0.12291	0.25581	0
13	6	13	0.06615	0.13027	0
14	9	14	0.12711	0.27038	0
15	10	11	0.08205	0.19207	0
16	12	13	0.22092	0.19988	0
17	13	14	0.17093	0.34802	0

B.2 Transmission Line Parameters: Values per circuit.

No.	From bus	To bus	x	b
1	5	6	0.25202	0.932
2	4	7	0.20912	0.978
3	4	9	0.55618	0.969

B.3 Transmission Line Parameters: Values per circuit.

Bus (Base: 100MVA)	P	Q
2	0.217	0.127
3	0.94	0.19
4	0.478	0.039
5	0.076	0.016
6	0.112	0.075
9	0.295	0.166
10	0.09	0.058
11	0.035	0.018
12	0.061	0.016
13	0.135	0.058
14	0.149	0.05

Publications

Z. Zheng, F. Li and V. Hamidi, “Assessment of Carbon Efficiency for power sector with consideration of network constrains”, *IEEE PES General Meeting*, 21-25 July 2013. Vancouver, Canada.

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